BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In The Matter Of the Application Of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Competitive Bidding for New Generating Capacity in Hawaii.	DOCKET NO. 03-0372

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PUBLIC UTILITIES COMMISSION

OPENING BRIEF

EXHIBITS "A" – "D"

AND

CERTIFICATE OF SERVICE

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TABLE OF CONTENTS

Page

INTRODUCTION 1

RESPONSES TO OUTLINE OF POST-HEARING QUESTIONS 7

I.A. 7

I.B. 29

II.A. 29

II.B. 39

II.C. 50

II.D. 63

II.E. 66

III.A. 67

III.B. 98

III.C. 107

III.D. 117

IV.A. 134

IV.B. 149

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In The Matter Of the Application Of **PUBLIC UTILITIES COMMISSION** **Instituting a Proceeding to Investigate Competitive Bidding for New Generating Capacity in Hawaii.**	**DOCKET NO. 03-0372**

OPENING BRIEF

Hawaiian Electric Company, Inc., ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), Maui Electric Company, Limited ("MECO") (collectively referred to herein as the "Company" or "HECO Companies"), respectfully submit their responses to the Commission's Outline of Post-Hearing Questions filed December 30, 2005 in this proceeding, Docket No. 03-0372.

INTRODUCTION

The key issues in this docket are (1) whether Hawaii electric utilities should implement competitive bidding for new generation, (2) what competitive bidding process, if any, should be implemented, (3) which resources should be subject to the competitive bidding process (since there are significant differences between central station firm capacity, distributed generation, and as-available renewable energy generation), (4) how should competitive bidding procedures be developed, and (5) how should such a competitive bidding process be "integrated" with the integrated resource planning ("IRP") process? These issues are not independent. (For example, competitive bidding using the wrong competitive bidding process should not be implemented.)

Stipulation

The positions of the HECO Companies on these issues, and support for the positions, are included in a proposed Framework. On May 22, 2006, the Company, Kauai Island Utility Cooperative ("KIUC") and the Division of Consumer Advocacy ("Consumer Advocate") filed with the Commission a Stipulation Regarding Proposed Competitive Bidding Framework ("Stipulation"). A proposed Competitive Bidding Framework (the "Proposed Framework" or "Framework") was attached as Exhibit A to the Stipulation. The remaining party in this proceeding, Hawaii Renewable Energy Alliance ("HREA"), did not sign the Stipulation.

The Stipulating Parties[1] are in agreement that each provision of their Stipulation and Proposed Framework is in consideration and support of all other provisions, and is conditioned upon acceptance by the Commission of all of the material matters expressed in the Stipulation and/or Proposed Framework. In the event the Commission declines to adopt material parts or all of the matters agreed to by the Stipulating Parties and as set forth in the Stipulation and/or Proposed Framework, any or all of the Stipulating Parties reserved the right to withdraw from the Stipulation and to pursue any and all of their respective positions through further negotiations and/or additional filings and proceedings before the Commission. (For purposes of the Stipulation, whether a term is material shall be left to the discretion of the Stipulating Party choosing to withdraw from the Stipulation.)

The Stipulating Parties are in agreement that they have addressed the benefits and impacts of competitive bidding in their written submissions and at the Panel Hearing, and the Proposed Framework is intended to capture potential benefits of competitive bidding while mitigating potential impacts.

[1] The HECO Companies, Consumer Advocate and KIUC are collectively referred to as the "Stipulating Parties".

Potential Benefits/Disadvantages of Competitive Bidding

The potential benefits and disadvantages of competitive bidding were addressed in Exhibit 1 to HECO's FSOP,[2] based primarily on the experience of HECO's consultant, Mr. Oliver, with competitive bidding on the mainland, and the application of that experience by Mr. Oliver and HECO to unique circumstances of Hawaii's electric utilities, and are summarized in Exhibit "A" to this Opening Brief.

Hawaii Utility Systems

In compiling the Proposed Framework, it was important for the Stipulating Parties to recognize that the needs of isolated utility systems in Hawaii are significantly different from the utility systems on the mainland, which needs to be taken into account in the design and development of a competitive bidding process and the associated rules and guidelines. In many areas of the U.S. mainland, utility systems are part of a larger regional market, which provides utilities with access to a range of power supply options and products and reduces reliability risk. (In a number of instances, these include existing merchant plants.) In these systems, failure of the supplier to deliver could result in the buyer being indemnified based on the financial penalties contained in the power purchase agreement. The financial nature of the contract provides the utility the opportunity to purchase replacement power at market prices. The seller has to compensate the utility the difference between the contract price and the market price. The utility is made financially whole and still has access to reliable power supplies in the broader market.

In an isolated power market such as Hawaii, the inability to procure other sources of

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[2] References to the Companies' Statement of Position ("SOP") filed March 14, 2005 and Final Statement of Position ("FSOP"), filed August 11, 2005 are intended to incorporate the references to the record and authorities cited in the SOP and FSOP. The citations generally will not be repeated in this Opening Brief for the sake of brevity.

power could be devastating. There is no "broader market" from which replacement power could be obtained. The utility needs the physical power to meet customer reliability requirements.

HECO FSOP, Exhibit 1 at 11-12.

To gain a better perspective on the unique nature of the Hawaii electric system relative to mainland systems, the major characteristics of each system are contrasted in Exhibit "B" to this Opening Brief.

Framework

The Framework is intended to provide minimum guidelines that, if satisfied, will result in an acceptable process. One purpose of the Framework is to avoid time-consuming dispute resolutions over process that will make competitive bidding counter productive. The framework should also provide the flexibility for the utility to adapt to circumstances and changing perceptions of what is a "good solicitation process." Thus, the Stipulation provides that: "The Proposed Competitive Bidding Framework . . . is intended to represent guidelines concerning the competitive bidding process, which guidelines are flexible enough to permit tailoring the process to specific circumstances, yet specific enough to avoid after-the-fact determinations of fundamental process matters." The Framework includes the following provision to reflect this intent:

> If the IRP Plan indicates that a competitive bidding process will be used to acquire a generation resource or a block of generation resources, then the utility will indicate, in the submittal of its draft RFP to the Commission for review, which of the RFP process guidelines will be followed, the reasons why other guidelines will not be followed in whole or in part, and other process steps proposed based on good solicitation practice; provided that the Commission may require that other process steps be followed.

Framework ¶III.H.6.

The Framework also provides that: "RFP processes should be flexible, and should not include unreasonable restrictions on sizes and types of projects considered, taking into account the appropriate sizes and types identified in the IRP process." Framework ¶I.B.5.

The Framework also specifies objectives that the competitive bidding process should meet. Framework ¶III.A.1-5. These include:

> 1. Competitive bidding should be structured and implemented in a way that facilitates an electric utility's acquisition of supply-side resources identified in a utility's IRP Plan in a cost effective and systematic manner, and all costs that would be incurred by the utility and its customers should be taken into account in the bid evaluation and selection process.
>
> 2. Competitive bidding should be structured and implemented in a way that facilitates the achievement of renewable portfolio standards, state energy policy, and other important IRP objectives.
>
> 3. Competitive bidding should be structured and implemented in a flexible and efficient manner that promotes electric utility system reliability by facilitating the timely acquisition of needed resources and allowing the utility to adjust to changes in circumstances.
>
> a. The implementation of competitive bidding cannot be allowed to negatively impact reliability of the electric utility system.
>
> b. The generating units acquired under a competitive bidding process must meet the needs of the utility in terms of the reliability of the generating unit, the characteristics of the generating unit required by the utility, and the control the utility needs to exercise over operation and maintenance in order to minimize system integration concerns.
>
> 4. The competitive bidding process should be fair and equitable to bidders, without being unduly burdensome on Hawaii electric utilities and public utility regulators.
>
> a. The competitive bidding process should include an RFP and supporting documentation by which the utility sets forth the requirements to be fulfilled by bidders and describes the process.
>
> b. When a utility advances its own project proposal (i.e., in competition with those offered by bidders) or accepts a bid from an affiliate, the utility should take reasonable steps to mitigate concerns over an unfair competitive advantage that may exist or reasonably be perceived by other bidders or stakeholders.
>
> 5. If an IPP, turnkey or affiliate proposal is selected as a result of the RFP process, one or more contracts are the expected result of the process, and proposed forms of PPAs and other contracts that may result from the RFP process (e.g., PPA for firm capacity, PPA for as-available energy, turnkey contract, etc.) should be included with each RFP.

RFP Review and Approval

Any process requiring formal approval of the request for proposal ("RFP") before issuance (rather than an informal process permitting regulators to comment on the RFP) could substantially and needlessly delay an RFP process, and render it unworkable. The Commission would formally approve the IRP Plan, and any determination therein to conduct or not conduct an RFP process, and the proposed scope of the RFP process. The Commission also would formally approve the outcome of the RFP process (or other resource procurement process), whether the outcome was a utility-built or utility-owned facility or facilities, or an IPP-owned facility or facilities, or a combination thereof. Both processes will need to be expedited for the overall process to be workable – given the time required for detailed engineering, subcontractor contracting, permitting, equipment procurement and construction after the outcome is approved.

PURPA

Before the adoption of the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"), utilities generally owned their own generation (either directly, or in some circumstances on the mainland, through affiliates so that larger generating units could be installed). The utility generally would acquire the components for the generating unit through competitive bidding (open to manufacturers or packagers of generating units), and competitively bid the engineering and construction contracts required to design and install the generating unit. Alternatively, the utility could also accept bids for generating units to be installed on a "turnkey" basis, in which case the utility would still own the generating unit and the site for the generating unit.

An alternative competitive procurement process was implemented in Hawaii as a result of PURPA. Qualifying facilities are allowed to submit offers to sell firm capacity and energy to the utility at prices at or below avoided costs, pursuant to the rules established by the Federal Energy Regulatory Commission ("FERC") under PURPA, and state rules (such as those in Title VI, Chapter 74 of the Hawaii Administrative Rules) implemented pursuant to the FERC rules. In Hawaii, the utility's resource plan generally is that developed pursuant to its IRP process, taking into account any updates based on more recent planning assumptions and forecasts. For firm capacity resources, avoided costs are determined using the Differential Revenue Requirements ("DRR") method, in which the utility's revenue requirements for its base resource plan are compared to the utility's revenue requirements (on a discounted present value basis) for a resource plan in which the IPP facility is allowed to defer or replace utility-owned new generation.

Developers seeking to move forward PURPA QF projects can continue to pursue PPAs with the utility. Neither PURPA, nor the Commission's PURPA rules, however, specify all of the terms and conditions that must be offered to QFs. Moreover, firm capacity payments are only required when capacity costs are avoided. In general, competitive bidding is anticipated to be the process to acquire firm capacity and/or long-term energy contracts from PURPA QF and non-QF projects. See Tr. (12/15), pages 1018-1022; HECO FSOP, Exhibit I, Issue 1, A.2; page 1 and HECO FSOP, Exhibit II, pages 36-37. The subject of PURPA and competitive bidding is discussed further in Exhibit "C" to this Opening Brief.

RESPONSES TO OUTLINE OF POST-HEARING QUESTIONS

In general, the Company's responses to the Commission's questions are based on the provisions included in the Framework.

I. Competitive Bidding: Mandatory or Voluntary?

A. Under what circumstances, if any, should the Commission require competitive bidding? Options:

1. Require competitive bidding in all circumstances, without exception
2. Require competitive bidding in all circumstances, with the exception of one or more of the HECO Utilities' three pending projects
3. Require competitive bidding in all circumstances, with the exception of --
a. one or more of the HECO Utilities' three pending projects
b. any project for which the competitive bidding would be impractical, due to
(1) size
(2) emergency timing
(3) lack of developer interest
(4) utility expansion or repowering
(5) other factors
c. An exemption for impracticality is available only after a Commission finding based on .a submission by the utility. A Commission finding of impracticality does not insulate the utility from a Commission finding that such impracticality was a result of utility imprudence.
4. Do not require competitive bidding in any particular case, but
a. require utility to file explanation of each decision to use or not to use competitive bidding, and
b. reserve to the Commission the authority to require competitive bidding in particular cases

* * *

6. Leave the determination for competitive bidding of resources to the IRP process.

<u>Response</u>

The Proposed Framework adopts the approach of I.A.6 (i.e., it leaves the determination for competitive bidding of resources to the integrated resource planning ("IRP") process), but incorporates elements from I.A.4 (the utility would include an explanation of any decision not to use competitive bidding, and the Commission would have the opportunity to review and modify that determination in acting on the IRP Plan) and from I.A.3 (by establishing competitive bidding as the preferred mechanism, unless shown to be unsuitable, while specifying circumstances under which competitive bidding is <u>not</u> expected to be, or may not be, the preferred mechanism (i.e., exceptions) and by grandfathering certain existing projects).

In general, the determination as to whether competitive bidding will be used to acquire resources or blocks of resources should be made in the IRP process, and indicated in the IRP Plan. Framework ¶¶I.A.2, I.C.3. The basis for such determination should be explained by the utility in its Integrated Resource Plan ("IRP Plan"). The Commission should have the opportunity to review and modify the determination made in the IRP process in reviewing and approving the IRP Plan.

The Framework provides guidance as when competitive bidding would be expected to be the preferred mechanism, and when it would not be expected to be preferred (i.e., exceptions) – to minimize disputes and "course" reversals that could unacceptably slow down the resource acquisition process.

The Proposed Framework, in ¶I.A.3, establishes that: "Competitive bidding, unless shown to be unsuitable, is . . . the preferred mechanism for acquiring a future generation resource or a block of generation resources." However, the Framework also provides in ¶I.A.3.a that: competitive bidding should be implemented only to the extent that it meets certain specified conditions. Moreover, the Framework provides in ¶I.A.3.e that: "When a competitive bidding process will be used to acquire a future generation resource or a block of generation resources, the generating units acquired under a competitive bidding process must meet the needs of the utility in terms of the reliability of the generating unit, the characteristics of the generating unit required by the utility, and the control the utility needs to exercise over operation and maintenance in order to reasonably address system integration and safety concerns."

In addition, the Framework should specify specific circumstances under which competitive bidding is not or is <u>not</u> expected to be the preferred mechanism for acquiring resources, as well as specific on-going projects to which the framework should not apply at all.

Proposed Framework

The Proposed Framework provides that, generally, a determination will be made in a utility's IRP proceeding as to whether a competitive bidding process should be used to acquire a future generation resource or a block of generation resources.[3] Proposed Framework, paragraph I.A.2.

In the Proposed Framework, competitive bidding, unless shown to be unsuitable, is established as the preferred mechanism for acquiring a future generation resource or a block of generation resources. The basis for a showing that the competitive bidding process is unsuitable will be explained by the utility in its IRP Plan. The following conditions apply:

> Competitive bidding should be implemented only to the extent that it (i) facilitates an electric utility's acquisition of supply-side resources in a cost-effective and systematic manner, (ii) offers a means by which to acquire new generating resources that are overall lower in cost and/or better performing than the utility could otherwise achieve, (iii) does not negatively impact the reliability or unduly encumber the operation and/or maintenance of Hawaii's unique island electric systems, (iv) promotes electric utility system reliability by facilitating the timely acquisition of needed generation resources and allowing the utility to adjust to changes in circumstances, (v) facilitates the achievement of renewable portfolio standards, state energy policy, and other important IRP objectives, and (vi) is fair and equitable to bidders, without being unduly burdensome on Hawaii electric utilities and public utility regulators.

Proposed Framework, paragraph I.A.3.a.

The Proposed Framework also provides that, "[w]hen a competitive bidding process will be used to acquire a future generation resource or a block of generation resources, the generating units acquired under a competitive bidding process must meet the needs of the utility in terms of the reliability of the generating unit, the characteristics of the generating unit required by the utility, and the control the utility needs to exercise over operation and maintenance in order to

[3] Competitive bidding may be utilized by a utility outside of the IRP process, if circumstances justify such action. Proposed Framework, paragraph I.C.4.

reasonably address system integration and safety concerns." Proposed Framework, paragraph I.A.3.e.

In addition, the Framework identifies, in ¶I.A.3.b, c, specific circumstances under which Competitive bidding is not expected to be or may not be the preferred mechanism for acquiring a future generation resource or a block of generation resources:

> b. Competitive bidding is not expected to be appropriate (i) when it would unduly hinder the ability to add needed generation in a timely fashion, (ii) when the utility and its customers would benefit if the generation resource is owned by the utility (for example, when reliability would be jeopardized by the utilization of a third party resource), or (iii) when more cost-effective and/or better performing generation resources are more likely to be acquired more efficiently through different procurement processes.
>
> c. Competitive bidding may not be appropriate in the case of (i) the expansion or repowering of existing utility generating units, (ii) the renegotiation of existing power purchase agreements, (iii) the acquisition of near-term power supplies for short-term needs, (iv) the acquisition of power from a non-fossil fuel facility (such as a waste-to-energy facility) that is being installed to meet a governmental objective, and (v) the acquisition of power supplies needed to respond to an emergency situation.

Short term power needs are situations in which there is an immediate need for additional generation capacity for a limited duration in order to reliably meet near-term demand for electricity. For example, short-term power needs may result from a delay in the planned addition of new capacity or higher than expected demand growth. Such shortfalls may be met through interim measures such as temporary DG installations at utility substations and other contingency and mitigation measures that can provide reserve capacity or firm energy to the grid until such time that a permanent capacity addition is implemented.

Emergency situations, in the context of ¶I.A.3.c, would include situations in which a significant generation shortfall exists such that load cannot be fully or reliably served. As an example, such an emergency situation may occur when there is a catastrophic failure of an existing generating unit or a natural disaster results in the destruction of a generating unit. Such emergency situations could occur until such time that Contingency Plans can be implemented and until new generation is designed, permitted, and constructed to permanently replace capacity lost.

The IRP Plan will specify the proposed scope of the RFP, if an RFP is determined to be the preferred mechanism to acquire a specific generation resource or block of generation resources. Proposed Framework, paragraph I.B.1. Competitive bidding should enable the comparison of a wide range of supply side options, including power purchase arrangements, utility self build options and turnkey arrangements (i.e., build and transfer options). Proposed Framework, paragraph I.B.2.

An evaluation of bids in a competitive bidding process may reveal desirable projects that differ from those in an approved IRP Plan. These projects may be selected if it can be demonstrated that such action would be expected to benefit the utility and its ratepayers. Proposed Framework, paragraph I.C.5.

In addition, an evaluation of bids in a competitive bidding process may reveal that the acquisition of any of the resources bid would not serve the interests of the utility or its ratepayers. In such case, the Framework provides that the utility may determine not to acquire such resources and should so notify the Commission. Proposed Framework, paragraph I.C.6.

<u>Discussion</u>

Competitive Bidding as Preferred Mechanism

The Proposed Framework, in ¶I.A.3, establishes that: "Competitive bidding, unless shown to be unsuitable, is . . . the preferred mechanism for acquiring a future generation resource or a block of generation resources."

As stated in their FSOP, the HECO Companies can support competitive bidding for certain forms of new generation _if_ it is structured in such a fashion that the potential benefits can be realized, and the potential disadvantages can be mitigated or eliminated, and _if_ appropriate exceptions are recognized. HECO FSOP at 1. The Proposed Competitive Bidding Framework is intended to capture potential benefits of competitive bidding while mitigating potential disadvantages, given the specific circumstances that apply to Hawaii.

It would be a mistake to focus only on the "concept" of competitive bidding in this docket. Most of the parties can hypothecate that competitive bidding will be beneficial, but there are practical realities that could make certain forms of competitive bidding detrimental in practice. The devil is in the details.

The decision whether to implement competitive bidding in Hawaii today, in order to increase the number of IPP-owned options considered by utilities when adding new generation, should _not_ be based on the conceptual benefits of competitive bidding, or the actual benefits of issuing an RFP to acquire new capacity in the mainland markets. As is shown in Exhibit III to HECO's FSOP, circumstances are substantially different than they are on the mainland in terms of sites, fuels and other features that may make alternatives attractive. Even on the mainland, utility-owned options are often the most attractive options available. HECO FSOP at 8.

Mainland models can serve as a guide in developing Hawaii guidelines.[4] However, a "conceptually-sound" process that works on the mainland, but ignores Hawaii's unique reality, could result in substantial harm to Hawaii's electric infrastructure, to the ability of Hawaii's electric utilities to meet the growing electricity needs of their customers, and to Hawaii's economy.

Hawaii specific factors that must be taken into consideration in designing a competitive

[4] See response to PUC-IR-27.

bidding program include (a) the very limited number of sites that are available to site new generation, and the difficult, time-consuming and uncertain process that must be followed to change land use designations in Hawaii in order to acquire new sites for generation, (b) the extended time that must be allotted to conduct the necessary environmental review for, and to permit and obtain the necessary approvals for, new generation, (c) the utility and island-specific constraints that constrain the size of new generation that can be added to the systems, and (d) the limited fuel options that are economically available in Hawaii. HECO FSOP at 2.

In order to reflect these considerations, the Framework provides in ¶I.A.3.a that:

> Competitive bidding should be implemented only to the extent that it (i) facilitates an electric utility's acquisition of supply-side resources in a cost-effective and systematic manner, (ii) offers a means by which to acquire new generating resources that are overall lower in cost and/or better performing than the utility could otherwise achieve, (iii) does not negatively impact the reliability or unduly encumber the operation and/or maintenance of Hawaii's unique island electric systems, (iv) promotes electric utility system reliability by facilitating the timely acquisition of needed generation resources and allowing the utility to adjust to changes in circumstances, (v) facilitates the achievement of renewable portfolio standards, state energy policy, and other important IRP objectives, and (vi) is fair and equitable to bidders, without being unduly burdensome on Hawaii electric utilities and public utility regulators.

Moreover, the Framework provides in ¶I.A.3.e that: "When a competitive bidding process will be used to acquire a future generation resource or a block of generation resources, the generating units acquired under a competitive bidding process must meet the needs of the utility in terms of the reliability of the generating unit, the characteristics of the generating unit required by the utility, and the control the utility needs to exercise over operation and maintenance in order to reasonably address system integration and safety concerns."

Exceptions and Possible Exceptions

The implementation of competitive bidding cannot be allowed to negatively impact the reliability of the electric utility system. The Hawaiian Islands have no interconnections with each other, and certainly are not interconnected with large mainland electric utility systems.

At the same time, the expected timeline to (i) complete an IRP cycle, (ii) bid, select, contract for and obtain approval for a new generating unit (whether an IPP or utility-owned unit), and (iii) then permit and install the new unit must be realistic, and cannot be based on wishful thinking to justify a competitive bidding process. The reality is that it takes substantially longer in Hawaii to complete many of these steps than on the mainland, and that the time required for some of these steps has lengthened in recent years. HECO FSOP at 6 and Exhibit II at 6.

Thus, the Framework provides that competitive bidding is not the preferred mechanism for acquiring a future generation resource or a block of generation resources when there would be inadequate time to use an RFP process. To help avoid this circumstance, the Framework includes the admonition that, "[i]n order for competitive bidding to be effectively and efficiently integrated with IRP, stakeholders must work cooperatively to identify and adhere to appropriate timelines, which may need to be expedited." Framework ¶I.C.1. In addition, the Stipulation itself provides that "in order for competitive bidding to be effectively and efficiently integrated with IRP, stakeholders must work cooperatively to identify and adhere to appropriate timelines, which may need to be expedited, and . . . they will work together to identify appropriate timelines in the IRP process."

The Framework should take into consideration "real world" situations that are likely to develop in Hawaii. For example, the City and County of Honolulu, the County of Maui, and the County of Hawaii are all considering municipal solid waste ("MSW") projects. The utilities need the flexibility to consider purchasing energy and capacity from these facilities without going though an RFP process, since the projects would be developed in timeframes set by the Counties in order to solve a societal problem – garbage disposal – in a more environmentally friendly manner. Thus, the Framework provides that "[c]ompetitive bidding may not be appropriate in the case of . . . the acquisition of power from a non-fossil fuel facility (such as a waste-to-energy facility) that is being installed to meet a government objective . . . ." Framework ¶ I.A.3.C.

Need for Flexibility

In addition, it simply is not possible to precisely forecast what the future will look like, for example, ten years from now. Loads may grow faster than expected, demand-side options may not be as successful as originally hoped, or other factors may accelerate the need for new generation. Just as IRP has to allow for the implementation of contingency options when planning assumptions and forecasts change, any competitive bidding process would have to allow for similar exceptions.[5] HECO FSOP at 6.

Given state energy policy, the Companies have been aggressively pursuing resources other than fossil-fuel generation, including energy efficiency demand-side management ("DSM") programs, load management DSM, combined heat and power systems, and renewable energy generation. As a result, the utilities need to be able to adjust their plans to add new fossil-fuel generation to take into account their success or lack of success in obtaining the necessary approvals to implement these other resources, and their success in obtaining customer acceptance of these resources (since they are often dependent on the plans of third-parties other than the utilities), and to adjust for changes in load growth. HECO FSOP at 10.

Timeline

[5] The competitive bidding process also should recognize the value of flexibility in the evaluation of resource alternatives. Such flexibility options as contract buy-out options, project in-service date deferral or acceleration provisions, or project acquisition options are valuable options for a utility to more effectively balance its needs with the cost of obtaining such options. Given the nature of their Island systems, the HECO Companies are also concerned about fuel flexibility and the option to convert to an alternative fuel if fuel cost or availability changes dramatically. HECO FSOP at 10. These considerations are addressed later in the Framework.

Implementing competitive bidding must not negatively impact electric system reliability. Accordingly, a reasonable estimated timeline must be developed to ensure that the competitive bidding process is not applied to resources whose need date is earlier than could be achieved under a competitive bidding structure. See HECO SOP at 2-4.

The expected timeline (1) to complete an IRP cycle, (2) to bid, select, contract for and obtain approval for a new generating unit (whether an IPP or utility-owned unit), and (3) to then permit and install the new unit must be realistic, and cannot be based on wishful thinking to justify a competitive bidding process. The reality is that it takes substantially longer in Hawaii to complete many of these steps than on the Mainland, and that the time required for some of these steps has lengthened in recent years. HECO FSOP, Exhibit II at 6.

A brief review of the major elements developing new generation through the Competitive Bidding Framework clarifies the length of the process. The process includes completing this proceeding, developing the competitive bidding process, implementing the process, developing the RFP, obtaining bids and choosing a final project, negotiating the contract, obtaining required permits and approvals, and obtaining and installing the new resource. For various reasons identified below, some of these elements can take significantly longer than anticipated, especially in Hawaii. HECO FSOP, Exhibit II at 7.

Factors affecting the development and implementation of an RFP process, assuming competitive bidding procedures were already in place before RFP issuance; include (1) whether or not the host utility has had recent experience with developing and implementing an RFP process; and the (2) type of resources solicited. The second step is determination of the scope of the RFP, which should take place in the IRP process. The third step is development and issuance of an RFP. Based on examples of other utilities involved in competitive bidding, the time to develop and issue the RFP, evaluate bids and award the project, and negotiate and execute a contract can range from 14 to 31 months. It is important to emphasize that this timeframe is predicated on the competitive bidding rules being developed before issuing the RFP. HECO FSOP, Exhibit II at 7.

Permitting in Hawaii

By far the longest part of the process in Hawaii is obtaining the appropriate permits and approvals for new generation. Hawaii has a very limited number of sites that are available to locate new generation, and changing land use designations or zoning in Hawaii in order to acquire new generation sites is difficult and time-consuming with an uncertain outcome. Additionally, extended time must be allotted for permitting and environmental review. HECO FSOP, Exhibit II at 7.

Any combustion based generation will require a Covered Source/Prevention of Significant Deterioration ("CS/PSD") permit, which is administered by the State of Hawaii Department of Health ("DOH") and the United States Environmental Protection Agency ("EPA"). The time necessary to apply for and obtain a CS/PSD permit varies widely depending on a number of factors including the size of the unit, its location, and the depth and extent of public participation or opposition. The permit review time period for recent HECO Companies units has varied from as much as 8.8 years (HELCO's Keahole CT-4/CT-5) to as little as 1.5 years (Maalaea X1-X2). In general, larger units have a longer permit review period than do smaller units. HECO FSOP, Exhibit II at 7.

Besides CS/PSD permitting, all new or expanded fossil-fired electrical generation units with output exceeding 5 MW must now undergo environmental review pursuant to Hawaii Revise Statutes ("HRS") Chapter 343, Hawaii's Environmental Impact Statement ("EIS") Law.

The time necessary for the HECO Companies to complete the environmental review process under the EIS Law has ranged from 8 to 21 months for large projects (both generation and transmission). The CA/PSD permit will not be issued until the EIS process has been satisfactorily completed. HECO FSOP, Exhibit II at 7-8.

It is also important to understand that the above timeline discussion assumes that the site for new generation is appropriately zoned or has the appropriate land use designation. Rezoning or obtaining a change to the land use designation will only add time to the process. HECO FSOP, Exhibit II at 8.

Mainland Timelines

The time required on the mainland to conduct and obtain approval of an RFP process, and to permit and install new generation, is considerably less than it is in Hawaii. HECO FSOP, Exhibit II at 8.

In Florida, the competitive bidding rules were already in place, and Florida Power & Light Company ("FPL") simply filed a request for determination of need with a need study. It took six and one-half months from issuance of the RFP to submit the petition to the commission, and three and one-half months for the commission to issue its decision. The approved combined-cycle unit was expected to be available three years thereafter. HECO FSOP, Exhibit II at 8.

In Utah, interim competitive bidding procedures were adopted by stipulation within three months of the opening of a competitive bidding docket. It took five months from the issuance of an RFP for PacifiCorp (dba Utah Power & Light) to submit a CPCN application for a phased combined-cycle unit to be used for peaking purposes, and twelve months from RFP issuance to submit a CPCN application for a base-loaded combined-cycle unit. The commission approved the respective applications after four months and five and one-half months. The first phase (a combustion turbine or "CT") of the first combined-cycle unit was expected to be available after fifteen months, with the completion of the unit in another year. The second combined-cycle unit was expected to take two and one-half years to install. HECO FSOP, Exhibit II at 8.

The timeframe to conduct an RFP process and to develop competitive bidding rules or guidelines has also taken a significantly longer amount of time. In the case of Portland General in Oregon it took 28 months to adopt competitive bidding guidelines, and 27 months to develop an RFP, obtain bids and negotiate and execute contracts. HECO FSOP, Exhibit II at 8.

Grandfathered Projects

In ¶I.A.3.d, the Framework identifies on-going projects to which the Framework would not apply: "This Framework does not apply to (i) the following utility projects that are currently being developed, including: HECO Campbell Industrial Park CT-1, HELCO Keahole ST 7, and MECO Maalaea M 18, or to (ii) offers to sell energy on an as-available basis by non-fossil fuel generation producers that are under review by an electric utility at the time this Framework is adopted."

With respect to the three "grandfathered" projects, it does not make sense to attempt to apply a new competitive bidding process retroactively to these projects, given (1) their status, (2) their timing, and/or (3) the nature of the projects. For example, it requires a substantial period of time to develop and implement a well-designed RFP process, and to permit and install new generation. HECO currently has an urgent need for firm generating capacity. Efforts to install a simple cycle peaking unit at Campbell Industrial Park have been under way since early 2003. Although the capacity to be provided by the unit is needed now, the unit is not expected to be installed sooner than 2009, because of the long lead time for environmental review, permitting and approvals, equipment procurement and construction. It would not be practical for this unit to be subject to competitive bidding, because a well-designed and effective competitive bidding process cannot be put into place and completed soon enough.[6] HECO FSOP, Exhibit II at 5.

With respect to Maalaea Unit 18, an alternative ownership option was considered impractical, as the installation of that unit will complete the conversion of MECO's existing simple cycle combustion turbines Maalaea Units 17 and 19 to a 2-on-1 combined cycle unit. The conversion requires that two heat recovery steam generators and a steam turbine-generator (Unit 18) be integrated with the existing Units 17 and 19. Unit 18 will be installed on MECO property and it is impractical to demarcate boundaries and associated responsibilities for all utility and non-utility facilities, including buildings, access lanes, laydown areas, and integrated piping, ductwork and wiring, if Unit 18 was to be non-utility owned. Moreover, non-utility ownership of Unit 18 would likely require duplication of utility and non-utility operational and maintenance staffs, resulting in higher overall operational expense and unwieldy complications in the coordination of work and schedules for the integrated combined cycle unit. However, although it is impractical for Unit 18 to be non-utility owned, all major equipment and construction services for Unit 18 will be procured through competitive bidding processes. HECO FSOP, Exhibit II at 6.

If, instead, a competitive bidding for new generation process were used to secure stand-alone replacement capacity that would otherwise be provided by utility installation of Unit 18, the conversion of Units 17 and 19 to combined cycle would not occur (or would occur at a

[6] SOP, Exhibit A, pages 8-9. If an IPP-owned peaking unit was selected through a new competitive bidding process adopted as a result of this proceeding, the unit would not be installed until several years beyond 2009. It would be imprudent to apply the new process to generation that has to be added earlier than the process could be completed, even if some form of "expedited" process was followed. HECO FSOP, Exhibit II at 5 n.3.

Based on the experiences in other states, it may take two years or more to prepare an RFP, solicit proposals, evaluate the proposal, select the winning bidder and negotiate a contract. It could then take another seven years for the utility to obtain approval of the contract, and the selected bidder to obtain the necessary permits, procure the necessary equipment, and construct the unit. HECO FSOP, Exhibit II at 5 n.3.

much later date), and the opportunity to increase the generating efficiency of Units 17 and 19 would be lost or substantially delayed. HECO FSOP, Exhibit II at 6.

Similarly, with respect to Keahole ST-7, installation of that unit will complete the conversion of existing simple cycle combustion turbines Keahole CT-4 and CT-5 to a 2-on-1 combined cycle unit. The same concerns about competitively bidding the Maalaea Unit 18 would apply to Keahole ST-7. In addition, the completion of ST-7 is needed to place baseloaded generating capacity on the west side of the island for voltage support. HECO FSOP, Exhibit II at 6.

With respect to HECO's simple cycle combustion turbine peaking unit at Campbell Industrial Park, competitive bidding was not considered because of the concerns identified above. HECO FSOP, Exhibit II at 6.

The lead time to permit and install even a simple-cycle combustion turbine in Hawaii is approximately seven years. Given this lead time, HECO began the process of preliminary engineering work in 2002 and began efforts to obtain the Covered Source Permit ("air permit") for a nominal 100 MW simple-cycle combustion turbine in January 2003. HECO submitted an initial application for the air permit with the State of Hawaii Department of Health ("DOH") in October 2003. The DOH deemed the initial application complete in November (the HECO IRP-3 Advisory Group was informed of the air permit application at the October 7, 2003 IRP Advisory Group meeting).

In December 2004, HECO submitted an amendment to its initial air permit application, in part to allow for the possibility that a second simple-cycle combustion turbine may be needed sooner than projected (for example, if energy efficiency and load management DSM, CHP and renewable energy program imports are not fully realized, or if system demand increased more than projected). The DOH deemed the revised air permit application for two simple-cycle combustion turbines complete in February 2005 and is currently in the process of reviewing the application.

In 2004 and 2005, HECO continued with efforts to permit, design, and install its next generating unit and a 2-mile long 138 kV transmission line between the AES substation and CEIP substation. These efforts included: (1) Continuing to work with the DOH and EPA to facilitate the review of the air permit application. (2) Meeting with west Oahu neighborhood boards and community leaders to present HECO's plans. (3) Selection of an engineering firm to begin the necessary engineering work to develop conceptual layouts of the next generating unit and to specify and select the combustion turbine package through a competitive bidding process without commitments to purchase. (4) Determining the Accepting Agency for the Environmental Impact Statement ("EIS"), so that the EIS Preparation Notice can be published. (4) Working with neighboring communities on a "community give back" plan for the new unit, which was subsequently completed, and an application was filed on June 17, 2005 in Docket No. 05-0146.

HECO issued a Request For Proposals for a nominal 100 MW combustion turbine on April 8, 2005, to three vendors including Alstom, Siemens-Westinghouse, and General Electric. The Alstom and Siemens-Westinghouse units have a capacity of approximately 107 MW. The General Electric unit, which was used as a proxy for the 100 MW class of simple cycle combustion turbines for IRP-3 due to the availability of vendor-supplied data for the unit, has a capacity of approximately 76 MW. HECO received on May 25, 2005 bids from the three vendors to furnish a nominal 100 MW combustion turbine. HECO evaluated the bids and selected the 100 MW Siemens SGT-3000E unit. On December 16, 2005 HECO signed a contract with Siemens for the purchase of the combustion turbine.

HECO filed an application to commit funds for the CT on June 17, 2005 in Docket No. 05-0145. However, given the long lead time of the permitting, engineering, equipment procurement and construction activities, it appears that 2009 is still the earliest that permitting and installation of the simple-cycle combustion turbine can be expected to be completed.

> *5. The three pending projects: showing of interest*
> > *a. Should the Commission require the utility to issue a request for showing of interest (i.e., a document less formal than an RFP)?*
> > *b. Assume the Commission requires the utility to issue a request for showing of interest. Assume further that one or more apparently viable respondents indicate interest. Should the Commission require an abbreviated competitive process? What elements should the process contain?*

Response

With respect to the questions posed in paragraph I.A.5 of the Commission's Outline of Post-Hearing Questions ("Commission Outline"), the Commission should not require the utility to issue a request for a showing of interest for the three projects already under development (i.e., HECO's simple cycle peaking unit at Campbell Industrial Park, MECO's Maalaea Unit 18, and HELCO's Keahole Unit ST-7). Each project is currently underway. (As previously discussed, the Proposed Framework would not apply to these three projects which are currently being developed. Proposed Framework ¶I.A.3.d.)

In addition, each of these projects is scheduled to be commissioned in the near future. The MECO Maalaea M 18 generating unit is scheduled to be commissioned in September 2006. HECO-H-13, p. 4; see also, CA-HECO-IR-13. The HELCO Keahole ST 7 generating unit is scheduled to be commissioned in October 2009. HECO-H-13, p. 3. The estimated commercial operation date of the HECO Campbell Industrial Park CT-1 unit is July 2009. HECO-H-8, p. 3.

Discussion

The Commission should not require the utility to issue a request for showing of interest for these three projects which are currently being developed. First, as previously discussed, the Campbell Industrial Park generating unit is needed now, and the HELCO and MECO units will be needed in the near future (i.e., in the 2009 and 2006 timeframes, respectively). As discussed further below, it is not possible to issue a request for showing of interest, to be followed by an "abbreviated competitive process" in time for the units to be available when needed by the utilities. For example, the request for a showing of interest and "abbreviated competitive process" would include (1) development of the request for a showing of interest, which presumably would include obtaining Commission approval of such document, (2) issuance of the request for showing of interest, (3) time for the bidders to review, evaluate and potentially submit a response to the request for showing of interest, (4) evaluation of the responses to the request for showing of interest, (5) development of the "abbreviated competitive process", which presumably would include obtaining Commission approval of such a process, (6) issuance of the notice to potential bidders of the abbreviated competitive process, (7) time for the bidders to review, evaluate and potentially submit a response to the abbreviated competitive process, (8) evaluation of the potential bidders' responses, (9) negotiation of the contract with the bidders selected, (10) obtaining Commission approval of the contract with the winning bidder, and (11) commencement of designing, permitting, engineering and constructing activities for the projects.

Second, it is not clear what benefit the utility and its ratepayers would receive by issuing a request for showing of interest. It is the Company's understanding that a request for showing of interest requests a non-binding submission from bidders. In other words, the bidders do not make a binding commitment to being able to achieve the milestones in their proposals. As a result, there may be a number of responses to the request for showing of interest, but after further discussions with the bidders who responded, the bidders may not be willing to make a binding commitment to meet the terms and conditions included in the documents issued as part of the abbreviated competitive process.

Further, the cost of developing and issuing a request for showing of interest and similar documents for an abbreviated competitive process, and evaluating and negotiating with the bidders who respond to such requests, is not insignificant. It is not apparent that the speculative benefits outweigh the costs of such an exercise.

Currently, there is no established procedure for a request for a showing of interest, and one would have to be developed that would address the following issues. How much and what kind of information would the Company include in a request for a showing of interest? How much time would interested parties have to respond? What criteria would be used to evaluate whether those showing interest were "viable respondents"?

Because a showing of interest presumably would be "less formal" than a bid, the request may draw responses from entities that would not pass even minimal pre-qualification requirements in a bid process. Assuming "viable respondents" could be identified, how would an "abbreviated competitive process" work? Currently, there are no procedures in place. Presumably the Company would prepare a Solicitation of Interest ("SOI"), but would it be submitted to the Commission for review? Would the SOI documentation include proposed forms of power purchase agreements or other contracts? How much time would be allowed for bidders to prepare and submit their showing of interest, and how much additional time would be needed for evaluation of the responses, selection and negotiation and Commission approval?

While all of this was going on, would the Company's work on these three projects simply come to a halt?

Would the developers provide their own sites? To require HECO, MECO or HELCO to make its site available to a developer would cause a number of problems that are covered in detail in the Company's discussion of Commission Outline III.A.4.

If IPPs were selected to provide the generation resources in place of these pending projects, HECO, MECO and HELCO would have to undertake parallel planning to protect against the contingency that one of the developer's might not finish a project. Because these three utility projects are already underway, the parallel plans most likely would be to simply continue with the projects until it became reasonably certain that the developers' projects would go into commercial operation on a timely basis. Any reasonable rule would allow for the recovery of the cost of parallel planning. Tr. (12/14) at 590-91.

Time is of the essence for these three projects. For example, the HECO Campbell Industrial Park generating unit is needed now because HECO has a reserve capacity shortfall. If it were possible, HECO would install the unit now. Tr. (12/13) at 468 (Sakuda). If a new developer were selected now for the Campbell Industrial Park project and a PPA was negotiated and approved literally "overnight", that developer would be starting the air permit process in 2006, as opposed to HECO's pending application that was filed in 2003. Tr. (12/13) at 468-69 (Sakuda). HECO approached the Department of Health and asked the Department to consider drafting the air permits for all three of the specific turbines that HECO was evaluating in order to expedite the process, but the Department refused saying that HECO needed to identify the specific machine that it planned to employ in order for the Department to proceed with the air-permitting process. Tr. (12/15) at 997 (Simmons). A developer selected in response to a showing of interest followed by an abbreviated competitive process would not be able to even begin the Department of Health air permit process until it had selected the specific machine that it would install at the project.

Given the time frame of HECO's Campbell Industrial Park combustion turbine project, it is unlikely that a "serious" bidder would agree to submit a proposal. The time frame is just too short. It is not apparent that a bidder could meet the in-service date of 2009 for a 100 megawatt project given the permitting schedule. Tr. (12/13) at 475-76 (Oliver).

Furthermore, the Commission should not order HECO to "test the market" for potential alternatives to the Campbell Industrial Park project because HECO has already made efforts to meet demand through other means. HECO reviewed combined heat and power alternatives and filed an application for a CHP program. HECO also proposed to do accelerated Demand Side Management as part of HECO's recent rate case, Docket No. 04-0113; the DSM aspect of the case was separated into a separate energy efficiency docket, Docket No. 05-0069. HECO entered into an agreement with an existing independent power producer, Kalaeloa Partners, L.P., for an efficiency improvement and a resulting gain of 28 megawatts. HECO also been implementing some substation distributed generation to gain some additional capacity and reduce the amount of the reserve margin shortfall prior to 2009. Tr. (12/13) at 473-75 (Williams).

As discussed above, the benefits of conducting such a process do not outweigh the negatives of issuing a request for a showing of interest for the three projects that are currently underway.

B. KIUC Exemption

The Company takes no position with respect to the questions posed in Commission Outline I.B.

II.A. How should the Commission integrate competitive bidding with IRP?

1. General questions

a. Which of the following options most efficiently integrates competitive bidding and IRP?

(1) The IRP process first identifies a preliminary preferred resource plan (including capacity, energy, timing, technologies and other preferred attributes); then the utility or IE conducts a competitive bidding process (with the IRP-determined characteristics described in the RFP); then the selected resources become the final integrated resource plan.

(2) The IRP determines the need for capacity and the timing of need; the RFP is developed and issued during the IRP cycle; the bids received are evaluated within the IRP process (like any utility option is normally evaluated within the IRP process); the IRP process then selects bids to be part of a preferred plan and a contingency plan; contracts are negotiated with the winning bidders.

b. Should the Commission require the utility to establish a separate competitive procurement process for as-available renewable energy generation?

c. What if a resource not identified in the IRP preferred plan seeks to compete for a slot?

d. What specific amendments are necessary to the IRP framework to achieve the integration?

Response

The HECO Companies propose that the IRP and RFP processes become integrated. Hawaii has a well established integrated resource planning process in place that would need to be revised to accommodate competitive bidding. In many jurisdictions, utilities have used the IRP process to provide strategic direction to the long-term resource acquisition process. The IRP has been used to determine the portfolio strategy of the utility (i.e. level of renewable resources desired, fuel diversity requirements, environmental attributes, etc.), identify the timing and amount of capacity needs, and the preferred technologies or resources based on an assessment of the estimated costs of potential resource options. The results and findings from the IRP process can provide the necessary inputs to the development and implementation of the RFP. Thus, in many jurisdictions, there is a close linkage between the IRP process and the RFP.

Of the several options for integrating the IRP and RFP processes, the HECO Companies recommend adopting the most common approach, which is to implement the competitive bidding process after the IRP process is initiated, a "preferred" plan is developed and an IRP Plan is filed with the Commission, and the Commission approves the IRP Plan (see Figure 1). The IRP can be performed using the current process followed by the HECO Companies. In this case, the role of the IRP is to identify the "preferred" resource plan, define capacity and energy requirements, the timing of need, any preferred technologies, and potentially any other preferred attributes. The IRP can also be used to identify any preferences or criteria for resource selection and can be used to determine avoided costs.

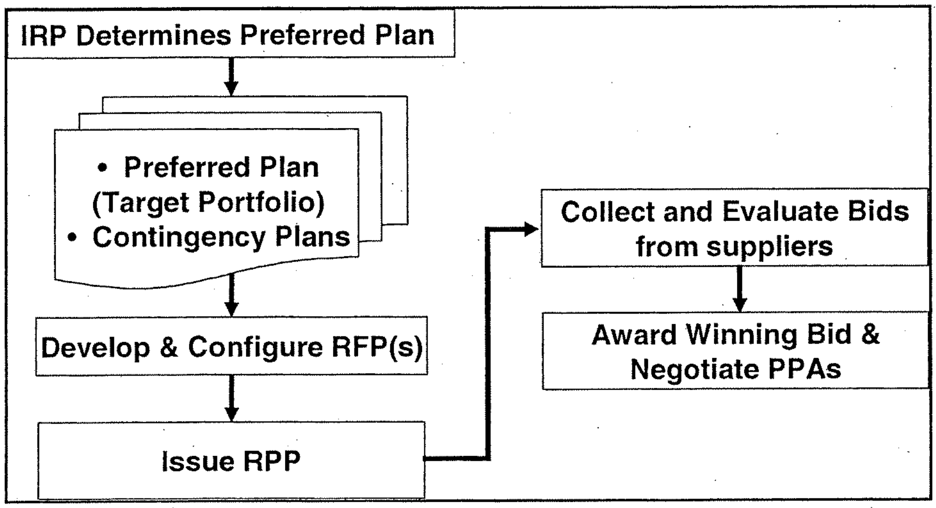

Figure 1: Preferred Resource Plan Followed by RFP Process and Resource Selection

In this model, the role of the RFP includes the solicitation and evaluation of generation resource or block of generation resources to meet the capacity and energy needs identified in the preferred resource plan. Bidders are allowed to submit proposals for any variety of resource types and sizes. The utility also has the right to submit proposals for resources that may differ from the preferred resource type included in the preferred resource plan. The bids received in response to the RFP are evaluated relative to one another and/or to the avoided costs of the generic resource identified in the IRP Plan or to the utility self-build project. The IRP Plan establishes the scope for the RFP. After the bids are evaluated and the resulting resource selected, the utility will then build the resource (if a self-build option is selected), or negotiate a turnkey contract or power purchase agreement (PPA) with the winning bidder (if a turnkey or PPA option is selected). The resulting resource(s) selected, once the projects are approved by the Commission, will be incorporated into the IRP Plan.

The advantages of this approach are that the IRP Plan is updated after the bids are received and evaluated, and the resulting resource(s) has been subjected to a competitive market test.

Should competitive bidding be implemented in Hawaii, revisions to the Framework for Integrated Resource Planning may be appropriate to account for the integration of the RFP process with the IRP process. It would be premature to propose specific changes to the IRP Framework before competitive bidding guidelines, if any, are adopted.

This approach effectively combines many of the features included in the options listed in II.A.1. Combining the features included in the options helps to minimize the negative impacts of those options. For example, as a practical matter, potential bidders may not be willing to take on the cost of preparing bids to respond to an RFP issued under the second option (Commission Outline II.A.1.a(2)). Bids are very costly to put together, and in some cases can cost as much as $500,000 to $1 million. Bidders are not going to take the risk of putting together a solid proposal in the second option process where they are not certain how that information is going to be used or if it is going to be used at all. Tr. (12/12) at 52 (Oliver). In addition, much of the information contained in a bid contains competitively confidential information (such as pricing details) that bidders may be unwilling to share in a public process such as IRP.

With regard to Commission Outline II.A.1.b, the HECO Companies acknowledge that competitive bidding processes may vary by resource type. There are significant differences between competitive bidding for firm power and competitive bidding for as-available or renewable resources, although even the as-available competitive bidding does introduce a number of technical issues that have to be addressed depending on the types and sizes of the resources being bid and the system characteristics. Tr. (12/12) at 219 (Simmons); Tr. (12/12) at 124-25 (Roose). An electric utility may establish a separate procurement process (such as a "set aside" or separate RFP process) to acquire as-available and/or firm capacity from renewable generating facilities. Proposed Framework, ¶I.B.4. Such an approach may be appropriate given the state energy policy that forms the development of renewable energy generation.

Responding to Commission Outline II.A.1.c, the Company recognizes that an evaluation of bids in a competitive bidding process may reveal desirable projects that differ from those in an approved IRP Plan. These may be selected if it can be demonstrated that such action would be expected to benefit the utility and its ratepayers. Proposed Framework, ¶I.C.5. On the other hand, an evaluation of bids in a competitive bidding process may reveal that the acquisition of any of the resources bid would not serve the interests of the utility or its ratepayers. In such case, the utility may determine not to acquire such resources and should so notify the Commission. Proposed Framework, ¶I.C.6.

Framework

The Commission's IRP Framework applicable to each electric utility should continue to be used to set the strategic direction of resource planning by Hawaii's electric utilities. In order for competitive bidding to be effectively and efficiently integrated with IRP, stakeholders must work cooperatively to identify and adhere to appropriate timelines, which may need to be expedited. Proposed Framework, ¶1.C.1. (A discussion of a process to streamline the IRP process is included in Exhibit "D" to this Opening Brief.) This Framework is intended to complement the Commission's IRP Framework. Proposed Framework, ¶1.C.2.

Generally, a determination shall be made in an IRP proceeding as to whether a competitive bidding process should be used to acquire a generation resource or a block of generation resources that is included in the IRP Plan. Proposed Framework, paragraph 1.C.3. The IRP Plan will specify the proposed scope of the RFP, if an RFP is determined to be the preferred mechanism to acquire a specific generation resource or block of generation resources.

Proposed Framework, ¶I.B.1.

Projects selected through competitive bidding processes should be consistent with the utility's approved IRP Plan (unless otherwise justified). See Proposed Framework, ¶II.B.1

Competitive bidding may be utilized by a utility outside of the IRP process, if circumstances justify such action. Proposed Framework, ¶I.C.4. An evaluation of bids in a competitive bidding process may reveal desirable projects that differ from those in an approved IRP Plan. These projects may be selected if it can be demonstrated that such action would be expected to benefit the utility and its ratepayers. Proposed Framework, ¶I.C.5.

2. Self-Build Option

a. Does the utility have a legal obligation to prepare a self-build option for each competitive bid?

b. Assume the utility has a legal obligation to prepare a self-build option for each competitive bid. What role should the utility's self-build option play in the competitive procurement process?

(1) The utility's self-build option competes directly in the competitive bidding process. Under this direct competition option, should the utility's self-build option be --

(a) announced in advance, in public, so competitors can try to beat it; or

(b) submitted one day in advance, in private?

(2) The utility prepares its self-build option in parallel to the competitive bidding process, as a backstop plan. Under this backstop approach,

(a) should the be backstop plan be described in the RFP?

(b) if a third party project is selected, at what point should the backstop plan be definitively abandoned?

(c) if no third party project is selected, or if a third party projected is selected but then fails,

i) must the utility proceed with the backstop plan without change,

ii) or should the utility be permitted (or required) to refine its backstop plan to take into account changes in circumstances since the backstop plan was formulated?

3. Parallel planning

a. Under what circumstances should the Commission require the utility to engage in parallel planning?

b. Should parallel planning be required for every selected third-party project?

c. Should parallel planning be required for every selected utility project?

d. At what point in the development of a selected project should parallel planning cease?

e. How should the Commission regulate this parallel planning and the associated cost?

(1) Should parallel planning activities be reflected in the IRP?

(2) Should parallel planning activities be anticipated in rate cases?

(3) Should the cost of parallel planning activities be deferred for consideration and recovery in subsequent rate cases?

<u>Response</u>

With respect to the response to Commission Outline II.A.2, please see the response to Commission Outline III.A.1 and 2.

<u>Framework</u>

If the utility does not seek to advance its project (i.e., over those of other developers), the utility should: indicate why relying on the market to provide the needed resource is prudent; develop a Contingency Plan[7] to respond in a reasonable timeframe if the competitive bidding process unexpectedly fails to produce a viable project proposal; and if necessary, identify a Parallel Plan[8] that is capable of being implemented, to the extent feasible, after an appropriate amount of planning, which may or may not be the supply-side resource or resources in the approved IRP Plan. Proposed Framework, ¶V.A.2.

Where the RFP process has as its focus something other than a reliability-based need, the utility may choose (or decline) to advance its own project proposal either in the form of a self-build or utility-owned project. Proposed Framework, ¶V.B.

[7] "Contingency Plan" refers to a utility's plan to provide either temporary or permanent generation or load reduction programs to address a near-term need for capacity as a result of an actual or expected failure of an RFP process to produce a viable project proposal, or of a project selected in an RFP. The utility's Contingency Plan may be different from the utility's Parallel Plan and the Utility Bid. Proposed Framework, ¶V.C (footnote 8).

[8] "Parallel Plan" refers to the generating unit plan (comprised of one or multiple generation resources) that is pursued by the utility in parallel with a third-party project selected in an RFP until there is reasonable assurance that the third-party project will reach commercial operation, or until such action can no longer be justified to be reasonable. The utility's Parallel Plan unit(s) may be different from that proposed in the Utility Bid. "Utility Bid" refers to a utility's proposal advanced in response to a need that is addressed by its RFP. Proposed Framework, ¶V.A.2.c (footnote 7).

Discussion

With respect to Commission Outline II.A.2.b(2)(b), a Parallel Plan should be pursued by the utility in parallel with a third-party project selected in an RFP until there is reasonable assurance that the third-party project will reach commercial operation, or until such action can no longer be justified to be reasonable. See Proposed Framework, ¶V.C.2.

With respect to Commission Outline II.A.2.b(2)(c), the utility should be permitted some flexibility in terms of how it proceeds especially if a third party project is selected but is not completed. If the RFP process results in the selection of non-utility ("third-party") projects to meet a system reliability need or statutory requirement, the utility should develop and periodically update its Contingency Plan and if necessary its Parallel Plan to address the risk that the third-party projects may be delayed or not completed. Proposed Framework, paragraph V.C. Such plans may include identification of milestones for such projects, and possible steps to be taken if the milestones are not met. Proposed Framework, ¶V.C.1.

Pursuant to such plans, it may be appropriate for the utility to proceed to develop a self-build or utility-owned project or projects until such action can no longer be justified as reasonable. The self-build or utility-owned project(s) may differ from the project(s) advanced by the utility in the RFP process, and/or the resource(s) identified in its approved IRP Plan. Proposed Framework, ¶V.C.2.

With respect to Commission Outline II.A.3, in consideration of the isolated nature of the island utility systems, the utility may use a Parallel Plan option to mitigate the risk that an independent power producer ("IPP") option may fail. Under this Parallel Plan option, the utility may continue to proceed with its Parallel Plan until it is reasonably certain that the awarded IPP project will reach commercial operation, or until such action can no longer be justified to be reasonable. Proposed Framework, ¶I.E.1. The electric utility may require bidders (subject to Commission approval with other elements of a proposed RFP) to offer the utility the option to purchase the project under certain conditions or events of default by the seller (i.e., the bidder), subject to commercially reasonable payment terms. Proposed Framework, ¶I.E.2. The utility's Contingency Plan may not necessarily be the resource identified as the preferred resource in its approved IRP Plan. Proposed Framework, ¶I.E.3.

The elements of a contingency plan may be identified in the IRP Plan to some extent. However, contingency plans must be flexible and be adjusted as circumstances change. For example, the contingency plan to address the possibility that an RFP process will not produce a viable resource would be adjusted to take into account the circumstances under which the RFP "failed". A contingency plan to address the possibility that the selected resource may fail will be based on the actual resource selected and the milestones in the contract for the resource. (For example, if an IPP project fails close to the time it is scheduled to go into service, the HECO Companies only reasonable option may be to install emergency generators rather than its own project.) Thus, it would be identified when the contract was submitted for approval.

With respect to the parallel planning cost recovery (Commission Outline II.A.3.e(2) and (3)), the costs that an electric utility incurs in taking reasonable and prudent steps to implement Parallel Plans and/or Contingency Plans shall be recoverable through a utility's rates as part of the cost of providing reliable service to customers. Proposed Framework, ¶VI.B.

The capital costs that are part of an electric utility's Parallel Plans and/or Contingency Plans should be accounted for similar to costs for planning other capital projects. Such costs would be accumulated as construction work in progress ("CWIP"), and carrying costs would accrue on such costs. If the Parallel Plans and/or Contingency Plans are implemented resulting in the addition of planned resources to the utility system, then the costs incurred and accrued carrying charges would be capitalized as part of the installed resources (i.e., recorded to plant-in-service) and added to rate base. The costs would be depreciated over the life of the resource addition. Proposed Framework, ¶VI.C.1.

If implementation of the Parallel Plans and/or Contingency Plans is terminated before the resources identified in such plans are placed in service, the costs incurred and accrued carrying charges included in CWIP would be transferred to a miscellaneous deferred debit account and the balance would be amortized to expense over five years (or a reasonable period determined by the Commission), beginning when the base plan resource is placed in service. The amortization expense would be included in revenue requirements when there is a rate case. Under appropriate circumstances, the Commission may allow additional carrying costs to accrue on the unamortized miscellaneous deferred balance. Proposed Framework, ¶VI.C.2.

The treatment of cost recovery for parallel planning in the Proposed Framework is consistent with ratemaking principles because, with respect to any cost incurred by a utility, if it is a prudent utility activity, there needs to be an effective cost recovery mechanism. A utility should be able to recover prudently incurred costs. Parallel planning costs are no exception. Generally, the Commission has determined that parallel planning costs are the responsibility of the ratepayers. Otherwise, the expense of parallel planning would be added to the cost of the project, and the IPP would have to recover that cost through the prices paid by the utility. In either situation, ultimately the cost recovery comes from ratepayers. Therefore, there should be a mechanism whereby ratepayers will pay for that cost, unless, because of the peculiar circumstances of a given project, there are unusually high parallel planning costs. In that case, the parallel planning costs should lower the IPP's profit on the project because one of the risks the IPP had to take in order to acquire that opportunity was the responsibility for the parallel planning cost. Tr. (12/14) at 740-742.

4. Definitions

a. Self-build option: the option created by the utility pursuant to its legal obligation to meet load. The self-build option is submitted in the competitive bidding process.
b. Parallel planning: the development efforts which the utility conducts when an independent bidder has been selected, to protect against the risk that the selected bidder fails to perform.

Response

The foregoing definitions of self-build option and parallel planning do not fully describe the ways in which these concepts should apply in a competitive bidding context. Please refer to the discussion of the terms Parallel Plan, Utility Bid and Contingency Plan above.

II.B. Design of Request For Proposals

1. Scope of RFPs

a. Should the utility use a formal RFP for all of its power needs, or only for those projects exceeding a certain size?
b. Should the Commission require the utility to use standard offer contracts?
c. Should the Commission allow the utility to choose between RFPs that target specific resources, or RFPs with broad-based eligibility requirements? Or should the Commission make this decision on a case-by-case basis? Or should this decision be made as part of the IRP process?
d. Should the utility use a formal RFP for all of its power needs, or only for those above a certain size?
e. Should the Commission require RFPs to seek proposals for each of the following, or leave the choice to the utility?

(1) conventional PPA
(2) tolling agreement
(3) fuel-sharing arrangement
(4) turnkey

Response

As discussed in response to Commission Outline I.A., an RFP should be considered for use as the preferred means to acquire a utility's new power needs, unless competitive bidding is shown to be unsuitable. The basis for a determination that competitive bidding is unsuitable would be explained by the utility in its IRP Plan. The Proposed Framework (¶I.A.3) sets forth conditions and possible exceptions that would apply to the competitive bidding process. The Proposed Framework does not include an exception based on the size of the proposed resource.

The Commission should not require the use of standard offer contracts. As discussed further below, the RFP would contain forms of proposed PPAs and other contracts. The terms and conditions of the contracts should be specified to the extent practical so that bidders are aware of some of the key provisions that affect risk allocation and provisions that may be subject to negotiation. However, it is not practical to offer standard offer contracts (i.e., a contract that is in "final" form and just needs to be signed by the bidder and utility). For example, certain contract provisions must reflect features of the winning bidder's proposal (e.g., technology, location).

As discussed further below, the decision as to whether competitive bidding should be used to acquire a specific future generation resource or block of generation resources should be made as part of the utility's IRP process. Once that determination is made in the IRP process, the utility will use the competitive bidding process to acquire resources that are consistent with those identified in the IRP Plan. However, the competitive bidding process may result in projects that differ from those in an approved IRP Plan. In such circumstances, these projects may be selected if it can be demonstrated that such action would be expected to benefit the utility and its ratepayers. In addition, in circumstances where it can be demonstrated that the acquisition of resources would not serve the interests of the utility or its ratepayers, the utility may make a determination to not acquire such resources and would notify the Commission. Further, competitive bidding may be utilized outside of the IRP process if circumstances justify such action.

The Commission should not require RFPs to seek certain types of proposals (i.e., conventional PPA, tolling agreement, fuel-sharing arrangement, turnkey).

Framework

The RFP process should allow for a solicitation of bids for either a block of resources as defined in the IRP Plan or for the next required resource identified in the IRP. Framework ¶I.C.3. The IRP Plan will specify the proposed scope of the RFP, if an RFP is determined to be the preferred mechanism to acquire a specific resource or block of resources. Proposed Framework ¶I.B.1.

The RFP may vary by type of resource. "Competitive bidding processes may vary by resource type. For instance, solicitation processes for distributed generation facilities may be different from those for central station generating supplies. An electric utility may establish a separate procurement process (such as a "set aside" or separate RFP process) to acquire as-available and/or firm capacity from renewable generating facilities." Proposed Framework ¶I.B.4.

The RFP process should allow for the utility to submit and/or select proposals for resources that may differ from the preferred resource type included in the IRP Plan recognizing that the planned generating additions can be altered as the utility pursues other options, including renewable technologies and additional cost-effective DSM programs. "An evaluation of bids in a competitive bidding process may reveal desirable projects that differ from those in an approved

IRP Plan. These projects may be selected if it can be demonstrated that such action would be expected to benefit the utility and its ratepayers." Proposed Framework ¶I.C.5. This planning strategy (rather than a fixed course of action) allows the development of alternate options to address alternate futures. Proposed Framework ¶I.B.5.

The RFP process should also allow for the utility to reject all resources under appropriate circumstances. Thus, the Proposed Framework provides in ¶I.B.6 that "An evaluation of bids in a competitive bidding process may reveal that the acquisition of any of the resources bid would not serve the interests of the utility or its ratepayers. In such case, the utility may determine not to acquire such resources and should so notify the Commission."

There are a number of forms of contract that may result from the RFP process. The Proposed Framework Paragraph III.A.5 provides that: "If an IPP or affiliate proposal is selected as a result of the RFP process, one or more contracts are the expected result of the process. Proposed forms of power purchase agreements ("PPA") and other contracts that may result from the RFP process (e.g., PPA for firm capacity, PPA for as-available energy, turnkey contract, etc.) should be included with each RFP." Guidelines regarding the terms and conditions in the contracts are addressed in ¶¶III.C.1, 2.

<u>Discussion</u>

The Commission should not require RFPs to seek proposals for each of the following: PPA, tolling and fuel-sharing agreements and a turnkey option. As noted above, the IRP Plan will specify the proposed scope of the request for proposals. The Commission will approve the IRP Plan. Within the parameters set by the IRP Plan, based on the expected system needs and conditions, the utility should have the discretion to specify the types of proposals or contract arrangements that it is seeking. The utility should design the RFP and submit the RFP and supporting documentation to the Commission which will be able to review the RFP and provide its comments to the utility.

The utility must be able to review the expected system needs and conditions at the time of the RFP. For instance, with respect to whether a tolling agreement is appropriate must be determined based on the particular resource the utility is seeking. The Company would have to examine each case and determine whether there would be benefits from pursuing a tolling agreement. Presently, there do not appear to be any opportunities where it would be beneficial for the HECO Companies to enter into a tolling agreement. Tr. (12/12) at 235-36 (Roose).

The Commission should not require the use of standard offer contracts. The RFP would contain forms of proposed PPAs and other contracts. The terms and conditions of the contracts should be specified to the extent practical so that bidders are aware of some of the key provisions that affect risk allocation and provisions that may be subject to negotiation. However, it is not practical to offer standard offer contracts (i.e., a contract that is in "final" form and just needs to be signed by the bidder and utility). For example, certain contract provisions must reflect features of the winning bidder's proposal (e.g., technology, location).

While some contract provisions could be finalized prior to the bidding process, a number of the provisions cannot be finalized as such provisions will be based on the characteristics of the winning bidder's proposal. HECO FSOP, Exhibit II, p. 29; see also, Tr. (12/14) at 604 (Roose). The HECO Companies' position regarding the inclusion of proposed forms of power purchase agreements and other contracts with the RFP prepared by the utility is set forth in response to Commission Outline II.C.

2. Pre-qualification requirements

a. Should the Commission require the utility to impose pre-qualification requirements?

b. Assume the Commission requires the utility to impose pre-qualification requirements. What pre-qualification requirements are appropriate?

(1) mature technology
(2) site control
(3) creditworthiness
(4) entry fee
(5) operational flexibility

Response

Responding to Commission Outline II.B.2, as discussed further below, the Commission should allow the utility to include a pre-qualification process that includes threshold criteria, but it should not be a requirement. In addition, the requirements listed in II.B.2.b are appropriate requirements. Other appropriate requirements and/or criteria are discussed further below.

Proposed Framework

The Proposed Framework contemplates a "multi-stage evaluation process" to reduce bids down to a short list or "award group" (i.e., a process that generally includes (i) receipt of the proposals, (ii) completeness check, (iii) threshold or minimum requirements evaluation, (iv) initial evaluation including price screen/non-price assessment, (v) selection of a short list, (vi) detailed evaluation or portfolio development, and (vii) selection of award group for contract negotiation). Proposed Framework, ¶III.B.1.d.

The Proposed Framework provides that a pre-qualification process may be incorporated in the design of some bidding processes, depending on the specific circumstances of the utility and its resource needs. Proposed Framework, ¶III.B.5. As part of the design process, the utility should develop and specify the type and form of threshold criteria that will apply to bidders. Examples of potential threshold criteria include requirements that bidders have site control, maintain a specified credit rating, and demonstrate that their proposed technologies are mature. Proposed Framework, ¶III.B.6.

The type and form of non-price threshold criteria should be identified in the RFP documentation. Such threshold criteria may include, among other criteria, the following:

a. project development feasibility criteria (e.g., siting status, ability to finance, environmental permitting status, commercial operation date certainty, engineering design, fuel supply status, bidder experience, and reliability of the technology);

b. project operational viability criteria (e.g., operation and maintenance plan, financial strength, environmental compliance, and environmental impact);

c. operating profile criteria (e.g., dispatching and scheduling, coordination of maintenance, operating profile such as ramp rates, and quick start capability); and

d. flexibility criteria (e.g., in-service date flexibility, expansion capability, contract term, contract buy-out options, fuel flexibility, and stability of the price proposal).

Proposed Framework, ¶¶III.E.9.a through d.

The Commission will have the opportunity to review and comment on threshold criteria when it reviews the utility's RFP. Proposed Framework ¶III.B.4.

Discussion

Project development feasibility criteria, project operational viability criteria, operating profile criteria, and flexibility criteria are important as these criteria help to evaluate whether a project can be built by the bidder within the timeframe proposed and according to the other specifications included in the RFP. For example, with respect to project development feasibility criteria, bidder experience is an important criteria. A typical threshold in this regard might be that a bidder must have completed one project of the same type and size as the project it is proposing. Other utilities have used a different number, two projects or three projects of a similar technology or three projects in total. A track record criterion also functions as a self-screen for the bidder. For example, if a wind developer receives an RFP for a 500 megawatt combined cycle project, it may think twice about submitting a bid because it may get eliminated up front because it does not meet the track record threshold criterion. Tr. (12/15/) at 968-69 (Oliver).

In addition, reliability of the technology is an important project development feasibility criteria. This criteria often requires that there must be facilities commercially operating that have performed up to their availability or capacity requirements. Tr. (12/12) at 114 (Oliver).

A common threshold criterion is a provision that bids must be submitted on time and meet all other administrative requirements identified by the utility. Tr. (12/12) at 118-19 (Oliver).

The HECO Companies expect that more stringent threshold criteria will be necessary for the island systems since the risk of project failure can be significant for utility customers. HECO FSOP, Exhibit II, p. 32.

If the Commission were to require the utility to impose pre-qualification requirements as assumed in Commission Outline II.B.2.b, any of the threshold criteria set forth in the Proposed Framework, or the other examples provided above, may be appropriate. However, decisions regarding the use and nature of threshold criteria should be left to the utility. It is difficult to come up with an exhaustive list of threshold criteria that should apply in all instances. Threshold criteria may differ depending on the scope of the RFP. For example, if the RFP specifically requested a wind resource of a particular size, there may be different threshold criteria that may be appropriate in comparison to an all source RFP. See Tr. (12/12) at 126 (Roose).

3. Process for developing RFP

a. Should the Commission require the utility to develop an RFP for each competitive procurement?

b. Should the Commission approve each RFP before issuance?
c. What generic features of an RFP should the Commission require the utility to develop, and obtain approval of, prior to a competitive procurement process?
d. Should the Commission require the utility to develop the RFP in consultation with interested parties, or leave this decision to the utility's discretion?
e. What procedures should the Commission require to limit appropriately the time required for Commission approval?
(1) informal meeting with Commission or staff during the development process
(2) Commission-imposed schedule for submittal of utility drafts, parties' comments, independent entity reports and Commission approval
(3) other

Response

If it is determined in the utility's IRP Plan that a competitive bidding process should be used to acquire a resource or resources, then an RFP should be developed for that competitive bidding process. As discussed in response to Commission Outline III.C, the Commission should not approve each RFP before issuance because the approval process could substantially delay the competitive bidding process and render it unworkable.

While the Company's position is that formal Commission approval of the RFP is not required, the Proposed Framework does provide certain general time frames for some of the steps in the RFP development and issuance process (e.g., time frame associated with release of draft RFP to issuance of the final RFP, time for the Commission to provide comments on the draft RFP before issuance of the final RFP). It is expected that the RFP would provide further timeframes in the RFP development and issuance process (e.g., time for parties to comment on the draft RFP).

Proposed Framework

Generally, a determination should be made in a utility's integrated resource planning proceeding as to whether a competitive bidding process should be used to acquire a future generation resource or a block of generation resources. Proposed Framework, ¶I.A.2. For a more complete discussion of this issue, please refer to the Company's response to the Commission Outline I.A.

The Proposed Framework provides a process leading to the distribution of the RFP that may include the following steps: the utility designs the RFP, then files its draft RFP and supporting documentation with the Commission; the utility holds a technical conference to discuss the draft RFP with interested parties (which may include potential bidders); interested parties submit comments on the draft RFP to the utility and the Commission; the utility determines whether and how to incorporate recommendations from interested parties in the draft RFP; the utility submits its final, proposed RFP to the Commission for its review; and the utility issues its RFP (the utility has the right to issue the RFP if the Commission does not direct the utility to do otherwise within 30 days of its having submitted its final, proposed RFP for review). Proposed Framework, ¶¶III.B.4.a through g.

Discussion

The Commission should not prescribe generic features that should be included in an RFP nor should the Commission require approval of generic features of the RFP prior to a competitive bidding process. As previously discussed, a process that includes formal Commission approval of the RFP before issuance could substantially delay an RFP process and render it unworkable. Such approval should not be necessary as the Commission will have an opportunity to review and comment on the RFP before it is distributed to prospective bidders.

With regard to Commission Outline II.B.3.d, the Commission and "interested parties" will have the opportunity to provide comments on the RFP before it is issued and the IRP Plan (which generally will be the basis for the RFP) so there should not be a requirement that the utility develop the RFP in consultation with interested parties. In addition, (1) the utility may hold a technical conference to discuss the draft RFP with interested parties (which may include potential bidders), (2) interested parties may submit comments on the draft RFP to the utility and the Commission, (3) the utility determines whether and how to incorporate recommendations from interested parties in the draft RFP, (4) the utility submits its final, proposed RFP to the Commission for its review, and (5) the utility issues its RFP (the utility shall have the right to issue the RFP if the Commission does not direct the utility to do otherwise within 30 days of its having submitted its final, proposed RFP for review). Proposed Framework, ¶¶III.B.4.b, c, d, f and g.

The process for the develop and issuance of the RFP included in the Proposed Framework is consistent with the approach taken in other jurisdictions, including Oklahoma, Utah and Louisiana, that use processes involving comments from bidders and comments from commission staff and other interested parties. Tr. (12/12) at 70-71 (Oliver).

In Commission Outline II.B.3.e, the Commission asks what procedures should the Commission require to limit the amount of time for Commission approval of the RFP. As discussed above, a process that includes formal Commission approval of the RFP before issuance could substantially delay an RFP process and render it unworkable. The Proposed Framework gives the Commission the opportunity to comment on the RFP before issuance and ultimately withhold issuance of the RFP. Proposed Framework, ¶III.B.4.g.

4. Content of RFP

a. Should the Commission specify any content to be included in the RFP? For example:

(1) characteristics of utility bid option

(2) information on relationship between utility and its affiliate

(3) method by which utility will weigh cost and noncost factors and rank bidders

Response

The Commission asks in II.B.4 whether it should specify any content to be included in the RFP. Under the Proposed Framework, the Commission would have a role in developing the content of the RFP when it approves the utility's IRP Plan. The IRP Plan will specify the proposed scope of the request for proposals, if an RFP is determined to be the preferred mechanism to acquire a specific generation resource or block of generation resources. Proposed Framework, paragraph I.B.1.

In addition, the Commission will have the opportunity to review and comment on the RFP when it is submitted to the Commission for review. For a more detailed discussion of this topic, please refer to the Company's response to Commission Outline II.B.3.c, above.

The Proposed Framework discusses a number of the subjects that would be included in the RFP. See e.g., Proposed Framework, ¶¶III.B.2, 3 III.C.1, III.E.9.

5. Definitions

a. Standard offer contract: A form contract, created in advance by the utility and modified and approved by the Commission, which constitutes a legal offer by the utility to buy from the third party. Acceptance by the third party forms a legally enforceable mutual obligation.

b. Pre-qualification requirement: a requirement which a bidder must satisfy to be eligible to bid

Response

The HECO Companies' positions regarding standard offer contracts and pre-qualification requirements are discussed above in response to Commission Outline II.B.1.b and II.B.2.

II.C. Design of Purchased Power Agreement

1. Should the Commission require each RFP to include model agreements (modified as necessary to reflect the particular resource desired) for each of the following, or should the Commission leave this choice with the utility?

a. conventional PPA

b. tolling agreement
c. fuel-sharing arrangement
d. turnkey agreement

Response

There are a number of forms of contract that may result from the RFP process. Paragraph III.A.5 provides that: "If an IPP or affiliate proposal is selected as a result of the RFP process, one or more contracts are the expected result of the process. Proposed forms of power purchase agreements ("PPA") and other contracts that may result from the RFP process (e.g., PPA for firm capacity, PPA for as-available energy, turnkey contract, etc.) should be included with each RFP." Guidelines regarding the terms and conditions in the contracts are addressed in ¶¶III.C.1, 2.

The role of the host electric utility in its competitive bidding process should include designing the RFP documents and proposed forms of power purchase agreements ("PPA") and other contracts. Proposed Framework, paragraph II.A.1.b. Thus, the Commission should leave to the utility the initial determination as to what types of proposed forms of contracts should be included with each RFP.[9]

Interested parties and the Commission should have the opportunity to comment on a draft RFP and the forms of contracts included with the RFP. Proposed Framework, paragraph III.B.4.

[9] The Proposed Framework does not use the term "model agreement" to avoid confusion with the concept of a standard contract or offer. For reasons explained in more detail below in the Company's responses to Commission Outline II.C.2 and II.C.3, it is not feasible to develop a "standard agreement" at the time the RFP is prepared, because some of the critical terms cannot be put into final form until the bids have been reviewed, the utility has selected a proposal and contract negotiations between the utility and the project developer have been concluded. For a discussion of the Company's position on so-called standard offer contracts, please refer to the Company's response to Commission Outline II.B.1.b. For a discussion of the Company's position regarding whether the Commission should require RFPs to seek proposals for conventional PPAs, tolling agreements, fuel-sharing arrangements and turnkey agreements, please refer to the Company's response to Commission Outlines II.B.1.e.

Proposed Framework

Proposed forms of PPA and other contracts that may result from the RFP process (e.g., PPA for firm capacity, PPA for as-available energy, turnkey contract, etc.) should be included with each RFP. Proposed Framework, paragraph III.A.5.

2. Process for developing PPA

a. Should the Commission require the utility to develop a PPA for each competitive procurement?

b. Should the Commission require the utility to submit, for Commission approval, a subset of PPA provisions that can serve as model provisions?

c. Assume the Commission requires the utility to submit, for Commission approval, a set of PPA provisions that can serve as model provisions. What are the PPA provisions appropriate for this treatment?

d. Should the Commission approve each PPA before issuance?

e. Should the Commission require the utility to develop the PPA in consultation with interested parties, or leave this decision to the utility's discretion?

f. Should the Commission review nonstandard PPA terms prior to the utility including the PPA in the RFP?

g. What procedures should the Commission require to limit appropriately the time required for Commission approval?

(1) informal meeting with Commission or staff during the development process

(2) Commission-imposed schedule for submittal of utility drafts, parties' comments, IE reports and Commission approval

(3) other?

Response

The Commission should not require the utility to develop a PPA for each competitive procurement as the Stipulating Parties' Proposed Framework provides that the RFP documentation should include proposed forms of PPA and other contracts. In addition, the terms and conditions of the contracts should be specified to the extent practical, so that bidders are aware of, among other things, performance requirements, pricing options, key provisions that affect risk allocation, and provisions that may be subject to negotiation.

If the Commission requires the utility to submit for Commission approval a subset of provisions that can serve as model provisions, the terms and conditions of the contracts that should be included as model provisions, include, to the extent practical, provisions concerning performance requirements, pricing options, key provisions that affect risk allocation (e.g., credit assurance and security requirements, contract buyout and project acquisition provisions, in-service date delay and acceleration provisions, liquidated damages provisions, turnkey options provisions), and provisions that may be subject to negotiation.

The Commission should not formally approve each form of PPA before issuance of the RFP for the reasons set forth in response to Commission Outline III.B.1.a. First, in order for each PPA to be reviewed and approved before issuance of the RFP would add a significant length of time to the competitive bidding process. Second, the RFP development process included in the Proposed Framework provides an opportunity for the Commission and interested parties to raise concerns about the contents of the PPA (which will be part of the RFP package), and the Commission will have the opportunity to review the final RFP (including the proposed forms of contracts, which are included as part of the RFP package) before it is issued and may stop the RFP from being issued. Further, the Company has already received guidance on a number of power purchase provisions, and the Commission has approved a significant number of power purchase provisions. In addition, the PPA that the Commission approved will likely have undergone changes as part of the refinement of the bidder's proposal (e.g., provisions will be tailored to match the bidder's specific proposed project).

Proposed Framework

Regarding Commission Outline II.C.2.a, b, c, d and f, the Proposed Framework provides that the RFP documentation should include proposed forms of PPA and other contracts, with commercially reasonable terms and conditions that properly allocate risks among parties in light of circumstances. The terms and conditions of the contracts should be specified to the extent practical, so that bidders are aware of, among other things, performance requirements, pricing options, key provisions that affect risk allocation (including those identified in the next paragraph), and provisions that may be subject to negotiation. Where contract provisions are not finalized or provided in advance of RFP issuance (e.g., because certain contract provisions must reflect features of the winning bidder's proposal such as technology or location), the RFP documentation should so indicate. Proposed Framework, paragraph III.C.1.

The provisions of a proposed contract should address matters such as the following (unless inapplicable): (a) reasonable credit assurance and security requirements appropriate to an island system that reasonably compensate the utility and its customers if the project sponsor fails to perform; (b) contract buyout and project acquisition provisions; (c) in service date delay and acceleration provisions; (d) liquidated damage provisions that reflect risks to the utility and its customers; and (e) contractual terms to allow for turnkey options. Proposed Framework, ¶III.C.2. The proposed contracts may allow the utility the option to request conversion of the plant to an alternate fuel if conditions warrant, with appropriate modifications to the contract to account for the bidder/seller's conversion costs and to assign the benefits of any lower fuel costs. Proposed Framework, paragraph III.C.3.

To the extent permitted by the RFP, bidders may request exceptions to the proposed contracts as part of their bids. The utility shall have the option of accepting or rejecting requested exceptions. Proposed Framework, paragraph III.C.4.

The utility will hold a technical conference to discuss the draft RFP with interested parties (which may include potential bidders). Interested parties submit comments on the draft RFP to the utility and the Commission. The utility determines whether and how to incorporate recommendations from interested parties in the draft RFP. Proposed Framework, paragraph

III.B.4.b, c and d. The Company's consultant, Wayne Oliver, has seen more success in a similar context where the PPA is spelled out in some detail and where the PPA is submitted and the bidders have the opportunity to red-line the PPA. Tr. (12/12) at 272.

Regarding Commission Outline II.C.2.e, please refer to the Company's response to Commission Outline II.B.3.d ("Should the Commission require the utility to develop the RFP in consultation with interested parties…?").

Regarding Commission Outline II.C.2.g, the Proposed Framework provides that the RFP (which would include proposed forms of PPA and other contracts) would be reviewed and commented on by interested parties and the Commission. The Proposed Framework also provides a timetable; namely, the utility will have the right to issue the RFP if the Commission does not direct the utility to do otherwise within 30 days of the RFP being submitted for review. Proposed Framework, paragraph III.B.4.

Discussion

It is simply not possible to develop a complete contract prior to the issuance of the RFP. A complete determination of what terms are appropriate can only be made after evaluating a bidder's proposal. For example, since many of the non-price provisions affect cost, and ultimately the price offered by the bidder, there is a trade-off between standardization and whether the utility can actually get a workable contractual arrangement. The Company has found in negotiating on a one-by-one basis that most of the non-price provisions that are significant tend to be subject to negotiation. Many are going to be specific to the technology. Some of the performance standards will be specific to a technology and cannot be standardized. The Company actually went through a process chaired by the Consumer Advocate to try to identify all the provisions that go into the power purchase agreements and try to get some agreements on which ones could be standardized and which ones could not. There were very few inputs to the contract that were identified as being capable of standardization. Tr. (12/12) at 244-46 (Williams).

Even something as seemingly simple as definitions can be difficult to establish in a proposed form of contract because the definitions in a PPA actually arise out of the types of provisions that are in the contract. If there are different performance standards, that will affect the definitions in the definition section of the contract. All the definitions that flow into provisions that are subject to negotiation also become subject to negotiation. Tr. (12/12) at 246 (Williams).

The Consumer Advocate took the position at the hearing in the present matter that Commission guidance in terms of what should be in a PPA is not going to be useful ahead of time because so many of the terms are going to vary with the type of product, and the ones that are not going to vary, i.e., the "boilerplate" terms, are not going to be disputed. Working out the terms of a PPA needs to be done within the RFP design rather than as an adjudicated proceeding at the Commission. Tr. (12/12) at 247-48 (Peaco).

Given the practical difficulties of developing specific contract terms, and considering that interested parties will have the opportunity to review and comment on the RFP and proposed forms of PPAs or other contracts before they are sent to potential bidders, there is no apparent benefit to be gained from the Commission ordering that PPAs contain a specific set of provisions.

The Proposed Framework strikes a balance between recognizing the benefits of providing guidance to bidders in formulating their proposals without requiring the creation of an unrealistic set of contract terms, some of which will be modified or eliminated during contract negotiations between the utility and the project developer submitting the proposal selected by the utility. The RFP documentation should include proposed forms of PPA and other contracts, with commercially reasonable terms and conditions that properly allocate risks among parties in light of circumstances. The terms and conditions of the contracts should be specified to the extent practical, so that bidders are aware of, among other things, performance requirements, pricing options, key provisions that affect risk allocation and provisions that may be subject to negotiation. Where contract provisions may not be finalized in advance of RFP issuance (e.g., because certain contract provisions must reflect features of the winning bidder's proposal such as technology or location), the RFP documentation should so indicate. Proposed Framework, paragraph III.C.1.

3. Content of PPA

What generic features of a PPA should the Commission require the utility to develop, and obtain approval of, prior to a competitive procurement process?

- *a. Definitions*
- *b. Pricing and payment schedule*
- *c. Quantity*
- *d. Duration*
- *e. Conditions Precedent*
- *f. Milestones*
- *g. Interconnection process*
- *h. Force Majeure*
- *i. Credit, security and insurance*
- *j. Construction approval and dispatch rights*
- *k. Regulatory out*
- *l. Dispute resolution*
- *m. Defaults*
    - *(1) developer inability to execute PPA after selection*
    - *(2) development delays*
    - *(3) generator nonperformance*
    - *(4) other*
- *n. Remedies*
    - *(1) forfeiture of security deposit*
    - *(2) liquidated damages*
    - *(3) utility ownership rights*

(4) other

Response

Please refer to the Company's response to Commission Outline II.C.2, above. All of the items listed could be addressed in the forms of PPA included with the RFP. However, the Commission should not formally approve each form of PPA before issuance of the RFP.

As stated above, the proposed forms of PPA and other contracts should include "commercially reasonable terms and conditions that properly allocate risks among parties in light of circumstances." The terms and conditions of the contracts should be specified to the extent practical, so that bidders are aware of, among other things, performance requirements, pricing options, key provisions that affect risk allocation and provisions that may be subject to negotiation. Proposed Framework, ¶III.C.1.

The provisions of a proposed contract should address matters such as the following (unless inapplicable): (a) reasonable credit assurance and security requirements appropriate to an island system that reasonably compensate the utility and its customers if the project sponsor fails to perform; (b) contract buyout and project acquisition provisions; (c) in service date delay and acceleration provisions; (d) liquidated damage provisions that reflect risks to the utility and its customers; and (e) contractual terms to allow for turnkey options. Proposed Framework, ¶III.C.2. The proposed contracts may allow the utility the option to request conversion of the plant to an alternate fuel if conditions warrant, with appropriate modifications to the contract to account for the bidder/seller's conversion costs and to assign the benefits of any lower fuel costs. Proposed Framework, ¶III.C.3.

4. Negotiations and dispute resolution

a. Should the Commission require the RFP to state that a bid binds the bidder if accepted by the utility?

b. In responding to an RFP, should bidders have an opportunity to propose amendments to a model PPA?
c. Should the Commission require the RFP to state that post-selection negotiations are permissible, but if not concluded within 60 days after selection will be resolved by the Commission based on written submissions only, pursuant to expedited procedures determined by the Commission at that time?
d. Should the Commission require competitive negotiations among short-listed bidders, subject to dispute resolution?
e. Concerning negotiations between the winning bidder and the utility, what forms of dispute resolution should the Commission allow or require?

Response/ Proposed Framework

Regarding Commission Outline II.C.4.a, the terms of the RFP and/or the proposed forms of PPA or other contracts could contain terms specifying the extent to which bidders would be bound by their bids. As a practical matter, bid acceptance would not occur immediately after bids are received. The utility may ask for clarification of bids. To the extent permitted by the RFP, bidders may request exceptions to the proposed contracts as part of their bids. The utility will have the option of accepting or rejecting requested exceptions. Proposed Framework, paragraph III.C.4. In addition, the utility may negotiate contract terms with selected bidders. Proposed Framework, paragraph II.A.1.f.

Bidders may request exceptions to the proposed contracts as part of their bids. In addition, there may be opportunities to negotiate price and non-price terms to enhance the value of the contract for the bidder, the utility and its ratepayers. Examples of such provisions that may be open for negotiation include fuel supply arrangements and project operating characteristics. Proposed Framework, ¶III.G.1.

As for Commission Outline II.C.4.b, bidders will have the opportunity to attend a technical conference to discuss the RFP and to submit comments on the RFP to the Commission. Proposed Framework, paragraph III.B.4.b and c. Bidders may also be able to negotiate price and non-price terms. Proposed Framework, paragraph III.G.1. In addition, bidders may request exceptions to the proposed contracts as part of their bids. The utility will have the option of accepting or rejecting requested exceptions. Proposed Framework, paragraph III.C.4.

With respect to Commission Outline II.C.4.c, the Commission should not mandate the inclusion of a term in the RFP that would require contract negotiations to be concluded in 60 days or be resolved by the Commission in an expedited adjudicatory procedure. Such a procedure would encourage a bidder to stonewall in negotiations with the utility hoping that the inevitable involvement of the Commission would enable it to secure its desired contract terms. In some RFPs in other jurisdictions, utilities can negotiate with another bidder if negotiations are taking too long with one bidder. Such a right encourages bidders to be more direct in contract negotiations. PUC-IR-74.

Commission Outline II.C.4.d asks whether the Commission should require "competitive negotiations among short-listed bidders, subject to dispute resolution." There is no need to require such a process. The Proposed Framework provides for a multi-stage evaluation process that will reduce bids down to a short list or award group. Proposed Framework, paragraph III.B.1.d. If negotiations with one bidder are not productive, the utility may move on to and negotiate with another bidder on the short list.

Please see the discussion in response to Commission Outline III.C.1.b for a discussion concerning dispute resolution for negotiations between the winning bidder and the utility.

<u>Discussion</u>

The goal of contract negotiations should be to advance the objectives of the Competitive Bidding Framework, the utility's IRP Plan and the specific RFP process in which the negotiations are taking place. The purpose of the contract negotiations is to take advantage of opportunities to enhance the value of the contract for the bidder, the utility and its ratepayers, as the provision states. This provision should be read in conjunction with Framework ¶III.C. The intent is not to re-do the deal.

In general, the utility would not seek to negotiate modifications to a term or condition that has been "accepted" by the bidder unless the modification is of mutual benefit. Whether the utility may change the terms of proposed forms of PPA after the RFP has been issued will depend upon the bidding procedures set forth in the RFP. The terms of the RFP may be influenced by comments of the Commission and interested parties as provided in paragraph III.B.4 of the Framework.

There are several steps involved in the contract negotiation process.

(1) In many RFPs, bidders are provided a form of power purchase agreement and have the opportunity to list exceptions to the contract. The utility has the option of agreeing to these exceptions. However, the exceptions at least provide the utility with a base of knowledge with which to begin contract negotiations.

(2) The utility also has to organize the contract negotiation team. The team generally consists of a lead attorney, a credit specialist, a commercial specialist, and possibly a system operations specialist. Negotiation of credit terms has become a very important aspect of the contract negotiation process over the past few years.

(3) During contract negotiations, senior management will be informed of the status of the negotiations process. Negotiations are not complete until the management (and sometimes the board] of the utility (and likely the developer as well) have agreed to all terms and conditions prior to submission of the contract for regulatory approval.

It is not uncommon for the contract negotiation process to take from 3-12 months. Contract negotiations in the recent Portland General RFP process took nearly 12 months to complete. To avoid such protracted delay, some utilities will establish a time limit for contract negotiations (i.e. 2 to 3 months) and specify the limit in the RFP document. The utility has the right to terminate negotiations and move on to the next bidder if a contract is not completed or substantially completed within that timeframe. This ensures the utility does not face reliability problems if a bidder negotiates for several months, terminates the project, and leaves the utility with no other alternatives. This would be particularly problematic in a utility system such as Hawaii.[10]

As indicated in Exhibit 1 to HECO's FSOP, the contract negotiation process on the mainland has become more complex and time consuming due to the poorer credit quality of a number of power generators, the requirements of the banks involved in project financing, and the requirements of the purchasing utility. There have been several recent examples of bidders agreeing to the major contract provisions outlined in the utility's form of power purchase agreement and then reneging on these requirements during the contract negotiation process. For example, Hydro-Quebec Distribution Company's first Call for Tenders included specific security requirements in both the Call for Tenders document and the model power purchase agreement. The winning bidder agreed to these requirements when it submitted its proposal. However, two months into the contract negotiation process, the bidder decided it could not accept the security provisions. Hydro-Quebec then terminated negotiations and had to initiate contract negotiations with the back-up bidder, effectively delaying the process by more than two months. This is not uncommon in the industry today in cases where the bidder is under no penalty if it decides to terminate negotiations or cancel the project. In a recent Call for Tenders involving BC Hydro, the utility included strict provisions in the contract that severely penalized a bidder from

[10] HECO FSOP, Exhibit 1 at 38.

terminating a project if it was selected as the winning bidder.[11]

II.D. Selection Process

Regarding the choice between "open" and "closed" bidding, should the Commission --
a. prohibit "open" bidding and require "closed" bidding?
b. require "open" bidding and prohibit "closed" bidding?
c. leave the choice with the utility?

Response

As discussed further below, the choice between "open" and "closed" bidding should be left with the utility. The Proposed Framework generally anticipates that a "closed" bidding process will be used.

Proposed Framework

A "closed bidding process" is generally anticipated, rather than an "open bidding process." Under a closed bidding process, bidders are to be informed through RFP documentation of (a) the process that will be used to evaluate and select proposals, (b) the general bid evaluation and selection criteria, and (c) the proposed forms of PPA and other contracts (e.g., turnkey contract). However, bidders may not have access to the utility's bid evaluation models or the detailed criteria used to evaluate bids, and/or information contained in proposals submitted by other bidders. Bidder access to evaluation scores and results will be at the discretion of the utility. Proposed Framework, paragraph III.H.3.

Discussion

As discussed in this Opening Brief, the Stipulating Parties' Proposed Framework provides a competitive bidding process that is fair and equitable to all bidders, clearly informs bidders of the requirements for bidding, provides guidance to bidders regarding the basis for "winning the bid," and includes reasonably transparent evaluation criteria that informs bidders of

[11] HECO FSOP, Exhibit 1 at 37.

the criteria of importance to the utility. Accordingly, the solicitation process should include thorough, consistent and accurate information on which to evaluate bids, a consistent and equitable evaluation process, documentation of decisions, and guidelines for undertaking the solicitation process. HECO FSOP, Exhibit II at 17.

It is HECO's position that the objectives of fair and equitable treatment of bidders and implementation of a reasonably transparent process can be met by use of a closed bidding process, which is more typical of current bidding systems in the industry. Under a closed bidding system, the utility usually provides a reasonable amount of information about the evaluation process and the methodologies to be used to evaluate bids, the criteria of importance to the utility, in some cases, the indices allowable to bidders for incorporation into their pricing formulae, and the basis for selecting a short-list and final award group. The RFP requests information from bidders that is used in the evaluation. Under a closed system, the bidder does not have access to the utility's bid evaluation models or the detailed non-price criteria used to evaluate individual bids. Bidders, therefore, have to focus on developing the details of their own project consistent with the information requested by the utility to ensure the bid is competitive and reasonably mature rather than attempt to maximize the points they would achieve in an open bidding system. In HECO's view, a closed system is more equitable and fair to bidders since gaming is not possible and such a process allows for a more detailed and comprehensive evaluation of all bids. The models used are more sophisticated and allow for a detailed assessment of the system impacts of all bids, thus capturing the true costs to customers. HECO FSOP, Exhibit II at 17.

HECO supports the position that a competitive bidding process should not be an open bidding process. The early competitive bidding processes were largely open, self-scoring processes. Self-scoring processes encouraged gaming since bidders would attempt to present information in their bids designed to maximize their point totals only. As a result, these processes led to significant litigation since bidders knew their own scores and could guess the scores of their competitors.[12] If bidders felt the scoring was in error, they would complain to the Commission. Furthermore, the price evaluation methodologies were simplistic, usually a spreadsheet which compared the net present value of the bid price against the net present value of the utility's projected avoided cost. Utilities were not able to optimize their portfolio because such simple models did not allow for project dispatching or reflection of other operating parameters associated with each proposal. Also, many of the projects accepted through these early self-scoring processes failed. Self-scoring systems are seldom (if at all) now implemented. HECO FSOP, Exhibit II at 17.

The closed bidding process should be designed to be a reasonably transparent bidding process, whereby bidders are informed in the RFP of the process used to evaluate and select bids, the evaluation criteria of importance to the utility, and the contract provisions of importance. Bidders need to know in general "how can I win the bid", but should not be in a position to influence the evaluation and selection process. In order to provide more transparency to the bidding process, in other competitive bidding processes, the utility may meet with commission staff to provide updates on the process. In addition, utilities generally develop thorough documentation of the evaluation and selection process for each bid, which can be reviewed with commission staff at the end of the process. HECO FSOP, Exhibit II at 20. Another solution is for the utility to retain an independent observer, under certain circumstances, as is discussed

[12] An example of open scoring is an early RFP by Boston Edison. In that RFP, bidders were awarded maximum points if they had more than a 50 percent equity ratio. IPPs at that time did not have 50 percent equity ratios, but many said they did in order to maximize their points. Then it was up to the utility to check on the IPP's claim regarding its equity ratio. That was a self-scoring system where a bidder could basically award itself points. Tr. (12/15) at 802-03 (Oliver).

elsewhere.

II.E. What Time Frame Should Apply to the Competitive Bid Process?

> *1. Should competitive bidding rules or framework include deadlines for the completion of each stage in the process?*
> *2. Should these deadlines apply to Commission approvals as well as to utility and bidder actions?*
> *3. What would be reasonable deadlines for each step in the competitive bidding process?*

Response

The types of resources that the utility will seek to acquire through the competitive bidding process could vary significantly. As a result, the length and complexity of the procurement process could also vary significantly. Therefore, in general, standard deadlines for each stage of the competitive bidding process should not be established by the framework. (As discussed further below, some deadlines for some steps of the competitive bidding process are capable of being established in the framework and the Stipulating Parties have proposed a general time frame for those steps.) Instead, the RFPs should establish the deadlines for each stage of the competitive bidding process. The deadlines in the RFPs would be tailored to fit the type of resource being acquired. As discussed in this Opening Brief, the Commission and interested parties will have the opportunity to comment on the RFP before it is issued (which will include the opportunity to comment on the deadlines included in the RFP) and the Commission will have the opportunity to stop the RFP from being issued.

Proposed Framework

While in general the RFP should establish the deadlines for the competitive bidding process, it is possible to establish some general time frames for some of the steps in the competitive bidding process. In designing the solicitation process, the utility should specify timelines. Proposed Framework, paragraph II.A.1.a. Once the utility has presented the RFP and proposed forms of contract to the Commission for review, the utility will have the right to issue the RFP if the Commission does not direct the utility to do otherwise within 30 days of its having submitted its final, proposed RFP for review. Proposed Framework, paragraph III.B.4.g. The timeframe associated with the process from release of the draft RFP to issuance of the final RFP may be approximately 75 to 90 days. Proposed Framework, paragraph III.B.9.

<u>Discussion</u>

Because the competitive bidding process begins during IRP planning, any consideration of deadlines for competitive bidding must take into account the timeframe for the utility's IRP cycle. This issue is discussed in the Company's response to Commission Outline II.A (dealing with integration of competitive bidding with IRP).

III.A. Utility Participation as Generation Competitor

1. Does the utility's service obligation require it to --

a. determine the need for new resources

b. validate each bidder's ability to serve

c. determine the operating flexibility necessary for a generating unit to fit reliably and economically into the utility's generation portfolio

d. determine the maintenance scheduling necessary for a generating unit to fit reliably and economically into the utility's generation portfolio

e. determine the interconnection facilities and transmission upgrades necessary to accommodate new generation

f. offer a self-build option in any competitive bid process

g. manage the RFP process, including

(1) designing the RFP documents, including the PPM;

(2) establishing evaluation criteria;

(3) communicating with bidders;

(4) evaluating the bids and selecting the winners;

(5) negotiating PPAs

<u>Response and Framework</u>

The frame of reference for this area is incomplete. The utility is <u>not</u> simply a potential competitor in its own RFP process. The utility, along with its customers and its system, are intended beneficiaries of any RFP process that is pursued or mandated.

It is the utility that has the obligation to serve. In Hawaii, the utility is not simply a provider of service, or the default provider of service, but is the provider of service.

The Proposed Framework (¶III.H) identifies steps that can be taken to provide bidders with reasonable assurance that their proposals will be "fairly" considered. This provision of the Proposed Framework indicates that those steps should not be implemented in a manner that creates an undue burden on the utility or its customers, who are the intended beneficiaries of the RFP process. The purpose of an RFP is to help the utility and its customers obtain new generation resources (See Proposed Framework ¶III.A.4.) that meet the objectives of the IRP "at the lowest reasonable cost", and to facilitate the acquisition of renewable energy resources (See Proposed Framework ¶III.A. 1.2.3.). The purpose is not to increase the amount of purchased power for the sake of competition, or to provide access to the Hawaii generation market on a "levelized playing field" basis. (See Tr. (12/14) at 671-72.) Making the RFP process unduly costly or resource intensive for small, island utilities would not be in the public interest, or be consistent with the purpose of issuing an RFP.

Competitive bidding will not be beneficial in Hawaii unless electric utilities are able to (1) participate as bidders in the process, and (2) conduct the competitive bidding process (which includes sending out the RFP, pre-qualifying bidders, evaluating the bids, and selecting the winning bid or bids). In order to encourage bidder participation, and to minimize disputes arising out of the bid evaluation and selection process, the steps that can be considered to facilitate a "fair" process are included in ¶III.H.7 of the Proposed Framework. This section addresses fairness and transparency issues related to the evaluation of a utility proposal against third-party bids in light of the different nature and types of risks associated with a utility and non-utility bid. In addition, this section describes the role of the Independent Observer in the process of evaluating utility proposals or affiliate bids against third party bids. (See Tr. (12/14) at 781-82.)

The roles of the host utility in the competitive bidding process should include: (1) designing the RFP documents, evaluation criteria, and power purchase agreement; (2) managing the RFP process, including communications with bidders; (3) evaluating the bids received; (4) selecting the bids based on the established criteria; (5) negotiating contracts with selected bidders; and (6) competing in the solicitation process with a self-build option, if feasible:[13]

> 1. All of these roles for the host utility are common in most RFP processes and are recognized by regulators and third-party bidders as reasonable roles for the host utility. Recent competitive bidding dockets have recognized the role of the utility and have supported an active role for the host utility. In fact, in several recent RFP processes, utility self-build or turnkey options have been the successful bidders among a large number of options.
>
> 2. Regulatory commissions have recognized that utilities have an obligation to serve and provide reliable service, and have an obligation to do so at lowest reasonable cost. Regulatory commissions also have recognized that acquisition of energy and capacity to meet the needs of customers remains the responsibility of the utility, and that these functions should not be delegated to an independent entity.
>
> 3. The goal of any competitive bidding process is to encourage and evaluate a range of generation options with the objective of obtaining the best option for the customers of the utility. This goal can only be assured if all resource options are allowed to compete. Regulatory commissions have recognized that a utility project may be the lowest cost option and failure to allow that option to compete may result in higher cost power options, contrary to their goals and objectives.
>
> 4. With regard to host utility self-build options, utilities have been selecting their own build options more frequently over the past few years for several reasons. First, the financial and credit problems faced by independent generators have led to higher debt costs and higher equity ratios for independent generators, virtually eliminating the competitive advantage once enjoyed by independent generators. Utility projects are now competitive from a financial perspective. Second, transmission constraints in a number of markets have led to higher transmission costs for resources located outside the utility service area or in costly transmission areas. Third, the deteriorating credit quality of many independent generators has raised concern over counter-party reliability. In turn, power purchase agreements require higher levels of security and tighter damage provisions to protect the utility's customers against the prospect of contract

[13] HECO FSOP at 7.

default. There is heightened concern that independent generators are less reliable than host utilities in developing and operating their projects.

The Proposed Framework provides that the role of the host electric utility in its competitive bidding process should include: designing the solicitation process, establishing evaluation criteria consistent with its overall IRP objectives, and specifying timelines; designing the RFP documents and proposed forms of power purchase agreements and other contracts; implementing and managing the RFP process, including communications with bidders; evaluating the bids received; selecting the bids for negotiations based on established criteria; negotiating contracts with selected bidders; and competing in the solicitation process with a self-build option, when appropriate. Proposed Framework, ¶¶II.A.1.a-g.

When a competitive bidding process will be used to acquire a future generation resource or a block of generation resources, the generating units acquired under a competitive bidding process must meet the needs of the utility in terms of the reliability of the generating unit, the characteristics of the generating unit required by the utility, and the control the utility needs to exercise over operation and maintenance in order to reasonably address system integration and safety concerns. See Proposed Framework, ¶I.A.3.e, III.A.3.b.

The bid evaluation process should include threshold criteria including bidder experience, reliability of technology, operation and maintenance plan, dispatching and scheduling and coordination of maintenance. (Commission Outline III.A.1.b, c, d and e). Proposed Framework, ¶III.E.9.a, b and c; see also Proposed Framework, ¶¶III.B.5, 6 and 7.

A utility is not necessarily required to present a self-build option in any competitive bidding process. Where the utility is addressing a need for firm capacity (i.e., where system reliability is at stake), the utility generally will be expected to develop a project proposal that is responsive to the resource need identified in the RFP, which represents its best ("self-build" or "utility-owned") response to that need in terms of foreseeable costs and other project characteristics. Proposed Framework, ¶V.A.1. If the utility does not seek to advance its project (i.e., over those of other developers), the utility should: indicate why relying on the market to provide the needed resource is prudent; develop a Contingency Plan to respond in a reasonable timeframe if the competitive bidding process unexpectedly fails to produce a viable project proposal; and, if necessary, identify a Parallel Plan that is capable of being implemented, to the extent feasible, after an appropriate amount of planning, which may or may not be the supply-side resource or resources in the approved IRP Plan. Proposed Framework, ¶¶V.A.2.a-c. Where the RFP process has as its focus something other than a reliability-based need, the utility may choose (or decline) to advance its own project proposal either in the form of a self-build or utility-owned project. Proposed Framework, ¶V.B.

In two recent competitive bidding proposals, these issues were clearly addressed.[14] The Staff Report and Recommendations prepared by the Staff of the Louisiana Public Service Commission in Docket No. R-26172 (Development of Market-Based Mechanisms to Evaluate Proposals to Construct or Acquire Generating Capacity to Meet Native Load), March 13, 2002 (page 4), clearly stated its objectives in considering the competitive bidding process.

> As many of the comments correctly recognize, the utilities have an obligation to serve and provide reliable service. They also have an obligation to do so at lowest reasonable cost. This rulemaking does not change those basic principles. Given this obligation, along with episodic problems in recent years associated with wholesale market supply (e.g. price spikes, shortages), the self-build option cannot be "taken off the table" in deference to the market. Moreover, the maintenance of a self-build option for utilities will help serve to discipline and restrain the market in the intermediate and long run.

Comments of bidders regarding utility participation in the RFP process were summarized

[14] HECO FSOP, Exhibit 1 at 18-19.

in the Order (page 3):

> Most commentators, however, recognized that utility projects may be appropriate if they pass a market test. As Sempra's witness states, the purpose of the RFP process is to "get the best deal for ratepayers in terms of cost, risks, reliability and environmental performance". It is possible that a utility self-build project -- vetted through an RFP -- could be the "best deal for ratepayers."

In its Order, the Louisiana Public Service Commission identified the role of the utility in the competitive bidding process as follows:

> After providing an opportunity for review, analysis and comment on the planning data and the draft RFP, the utility will proceed with the issuance of the RFP and review of the bids received. Staff and qualifying participants (those entitled to review the confidential bids) will have an opportunity to review the bids and the utility's evaluation analysis of those bids. Based upon the RFP results and its evaluation, the utility may choose to proceed with its self-build option or enter into contract negotiations with one or more bidders (or both). Staff (and qualified participants) will have the opportunity to provide input on the utility's bid evaluation and resource selection. (Page 5 of the Commission's Order, Feb. 16, 2004)

Likewise, the Staff Report prepared by the Staff of the Arizona Public Service Commission (Competitive Solicitation Docket NOS E-00000A-02-0051 ET AL), October 25, 2002 (page 8) concluded:

> The utility will be responsible for preparing the solicitation and conducting the solicitation process. Acquisition of energy and capacity to meet the needs of customers remains the responsibility of the utility, and the utility shall use accepted business standards for acquiring these resources, as it does when it buys all other products used in providing service.

In other recent RFP processes, self-build options have been allowed and encouraged.[15] For example, the Oregon Public Utility Commission allowed Portland General to offer a self-build option as a result of a revision to its 1991 competitive bidding rules, which stated that utility self-build options were not eligible to bid. Portland General had to submit its proposal to

[15] HECO FSOP, Exhibit 1 at 19-20.

the Commission in advance of receipt of other bids and had to provide the same information required of other bidders.

The bidding rules in Quebec allow Hydro-Quebec Generation to bid into the Distribution Company's Call for Tenders process as long as everyone abides by the same rules. The Generation Company has been awarded contracts but other independent power producers have been successful bidders as well.

2. Utility self-build option

a. For each resource need, should the Commission require the utility to present a self-build option?

b. Assume that for each resource need, the Commission will require the utility to present a self-build option. Which of the following choices are appropriate role for the self-build option?

(1) a bid to be evaluated like any other bid, submitted confidentially one day ahead of deadline

(2) a backstop proposal, to be utilized only if a winning project fails, regardless of whether the winning project's cost exceeds the backstop's cost

(3) a benchmark proposal, announced and described in detail at the time of the RFP, such that a nonutility bid must better the utility's benchmark to be considered

(4) other

c. Are there any circumstances under which the Commission should exempt the utility from identifying a self-build option?

d. Structural separation issues

(1) Assume that (a) the Commission will mandate that the utility offer a self-build option; (b) the Commission will require the self-build option to come from the utility rather than a utility affiliate; and (c) an independent observer will monitor, and certify the appropriateness of, each stage in the competitive bidding process.

(2) Should the Commission require an arms-length relationship between (a) the utility staff running the competitive bid process and (b) the utility staff preparing the self-build option?

(3) Assume the Commission will require an arms-length relationship between (a) the utility staff running the competitive bid process and (b) the utility staff preparing the self-build option. What structural measures are necessary to create this arms-length relationship? Consider all of the following, plus other appropriate measures:

(a) There must be a written code of conduct signed by all employees involved, which code assures that there is no special treatment or advantage granted to the self-build project.

(b) The self-build bid team and RFP evaluation team must be in different buildings, with neither having access to the others building
(c) There is a prohibition on any oral or written contacts during the RFP/bid evaluation process between the utility's employees preparing the self-build option and the utility's employees on the bid evaluation team, other than contacts authorized by the Code of Conduct and the RFP.
(d) All bid information must be maintained on a separate computer system to which no employee of the self-build team has access
(e) Any requests for clarification of the RFP be in writing, with the request and the utility's response immediately posted to the RFP website and served by email on every other party that has indicated an interest in responding to the RFP.
(f) A company officer must have explicit, written authority and obligation to enforce the code of conduct. Such officer shall certify, by affidavit, Code compliance by all employees.

Response

In general, the utility's proposal (or proposals[16]) is treated as a bid, but submitted one day ahead of the deadline for bids.[17] However, the result of selecting the utility's self-build proposal would not be a contract with itself. Thus, the unique risks and advantages of a utility self-build option would have to be evaluated, with the Independent Observer serving to "validate" the utility's evaluation. See Proposed Framework ¶III.H.7.

The utility's proposal would not be merely a "backstop" proposal, which would exclude the utility from participating. "Backup proposal" appears to connote the parallel plan, which may be different than the utility's self-build proposal. If the utility does not submit a self-build option, and no third-party option is selected in the RFP process because all proposals are inferior to the "benchmark" resource in the IRP Plan, then the utility may elect to request approval of that project in order to meet a reliability need if the timing of the need now precludes a further RFP

[16] A utility may propose several projects to meet certain types of RFPs, since more than one resource may be acquired pursuant to an RFP.
[17] By sending its proposal to the Commission in advance, other bidders would be ensured that the utility could not adjust its bid price or project structure after reviewing other proposals. HECO FSOP, Exhibit II at 18.

process.

It also should be noted that the utility's parallel plan[18] to "backstop" a non-utility project selected through the RFP process would not necessarily be the same as the utility's self-build proposal.

The utility's proposal would not be a "benchmark" proposal.[19] The IRP Plan generally would serve as the "benchmark" against which (or in the context of which) all proposals would be considered, and the utility's proposal would not necessarily be the same as a resource included in the IRP Plan. The parameters established by the preferred plan would include capacity and energy requirements, the timing of need, any preferred technologies, and potentially any other preferred attributes. Resource plans would be compared using the resource-in/resource-out method[20], with the preferred plan as the basis.[21]

Also, a non-utility bid would not necessarily have to "better" the IRP Plan benchmark to be considered, since the IRP Plan would be based on estimates, and the RFP process generally would be a better indicator of what the market actually can deliver. An evaluation of bids in a competitive bidding process may reveal that the acquisition of any of the resources bid would not serve the interests of the utility or its ratepayers. In such case, the utility may determine not to

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[18] "Parallel Plan" refers to the generating unit plan (comprised of one or multiple generation resources) that is pursued by the utility in parallel with a third-party project selected in an RFP until there is reasonable assurance that the third-party project will reach commercial operation, or until such action can no longer be justified to be reasonable. The utility's Parallel Plan unit(s) may be different from that proposed in the Utility Bid. "Utility Bid" refers to a utility's proposal advanced in response to a need that is addressed by its RFP. Proposed Framework ¶V.A.2.c (footnote 7).

[19] The utility self-build proposal is submitted separately, and may differ from what is commonly referred to as a "benchmark" proposal (i.e., a resource in the IRP Plan) to which all proposals may be compared, particularly if no self-build resource is submitted.

[20] Refer to Appendix B in the HECO Companies' Electric Utility System Cost System filings (Avoided Cost Methodology).

[21] The IRP Plan will define resources that were selected based on assumptions that were applicable at the time the plan was selected. However, actual conditions can deviate from the assumptions upon which the preferred plan was selected. Bids must be evaluated on the basis of actual conditions at the time the bids are evaluated.

acquire such resources and should notify the Commission. Proposed Framework ¶I.C.6.

Publication of benchmark cost information would send the wrong signal to bidders and could serve as a price cap. Bidders will attempt to price up to the cap but may not focus on preparing the lowest cost bid. HECO FSOP, Exhibit II at 14. See also,Tr. (12/12) at 131 (Oliver). It is now more typical that utility projects are submitted a day in advance, and bidders don't have the option to see what those prices are because it is a way of trying to put all projects on an equal footing. Tr. (12/12) at 133 (Oliver).

The utility should not be "required" to identify a self-build option. The proposed Framework does provide, however, that:

> The utility generally will be expected to develop a project proposal that is responsive to the resource need identified in the RFP, which represents its best ("self-build" or "utility-owned") response to that need in terms of foreseeable costs and other project characteristics.

The HECO Companies prefer to maintain the option for submitting a bid in response to the RFP and utilizing the time between the submission of the IRP and the date bids are due to refine the characteristics and pricing of its own resource option to ensure, among other things, that it includes the most up-to-date information available to provide the lowest reasonable cost option for their customers.[22]

The underlying assumption is that the market will deliver sufficient options to make competitive bidding worthwhile. That may or may not be the case, depending on the type of resource required. (If it generally will not be the case, then competitive bidding should not be mandated or encouraged.) In addition, if the utility's self-build option will be subject to cost recovery constraints that differ from those under traditional ratemaking, then it is questionable

[22] See HECO Response to PUC-IR-34.

whether the Commission can require the utility to submit a self-build option, or whether such a requirement would even be meaningful (since the utility could bid conservatively in any event).

Framework

The Proposed Framework addresses the self-dealing concern raised in Commission Outline III.A.2.d. If proposed utility self-build facilities or other utility-owned facilities (e.g., turnkey facilities), or facilities owned by an affiliate of the host utility, are to be compared against IPP proposals obtained through an RFP process, the electric utility should retain an independent observer to monitor the utility's conduct of its RFP process, advise the utility if there are any fairness issues, and report to the Commission on progress and results at various steps of the process. Proposed Framework, ¶III.H.7. Any negotiations between a utility and its affiliate during the course of a solicitation process shall be closely monitored by the independent observer. Specific tasks to be performed by the independent observer shall be identified by the utility in its proposed RFP documentation. Proposed Framework, ¶II.C.1.

The independent observer will review and track the utility's execution of the RFP process to ascertain that no undue preference is given to an affiliate and its bids, or to self-build or other utility-owned facilities. This may include, to the extent necessary, (a) reviewing the draft RFP and the utility's evaluation of bids, monitoring communications (and communications protocols) with bidders, (b) monitoring adherence to codes of conduct; and monitoring contract negotiations with bidders, (c) validating the utility's evaluation of affiliate bids, and self-build or other utility-owned facilities, and (d) validating the utility's evaluation of an appropriate number of other bids, at the discretion of the independent observer and the Commission. Proposed Framework, ¶III.H.7.

The utility may provide the independent observer with the utility's evaluation of the unique risks and advantages associated with utility self-build or other utility-owned facilities, including the regulatory treatment of construction cost variances (both underages and overages) and costs related to equipment performance, contract terms offered to or required of bidders that affect the allocation of risks, and other risks and advantages of utility self-build or other utility-owned projects to consumers. The independent observer may validate the criteria used to evaluate affiliate bids and self-build or other utility-owned facilities, and the evaluation of affiliate bids and self-build or other utility-owned facilities. In order to do this, the utility (in conjunction with the independent observer) should propose methods for making fair comparisons (considering both costs and risks) between the utility-owned or self-build facilities and third-party facilities.[23] Proposed Framework, ¶III.H.7.

Where the electric utility is responding to its own RFP, or is accepting bids submitted by its affiliates, the utility will take additional steps to avoid self-dealing in both fact and perception. Some steps should be done as a matter of course (i.e., regardless of whether the utility or its affiliate is seeking to advance a resource proposal), including: (i) the utility should develop all bid evaluation criteria, bid selection guidelines, and the quantitative evaluation models and other information necessary for evaluation of bids prior to issuance of the RFP, (ii) the utility should establish a website for disseminating information to all bidders at the same time, and (iii) the utility should develop and follow a Procedures Manual, which describes (1) the protocols for communicating with bidders, the self-build team, and others, (2) the evaluation process in detail and the methodologies for undertaking the evaluation process, (3) the documentation forms including logs for any communications with bidders, and (4) other information consistent with

[23] Such a comparison between self-build or other utility-owned facilities and IPP facilities may include modeling likely variation in construction costs, plant efficiency, plant outages, and/or operation and maintenance costs and assigning a risk premium to the self-build or other utility-owned facilities, and the likely impact of IPP proposals on the utility's capital structure.

the requirements of the solicitation process. Proposed Framework, ¶III.H.8.a.

Some steps should be done whenever the utility or its affiliate is seeking to advance a resource proposal, including (i) the utility should submit its self-build option to the Commission one day in advance of receipt of other bids, and provide substantially the same information in its proposal as other bidders; and (ii) the utility should develop and follow a Code of Conduct, and may implement appropriate confidentiality agreements prior to issuance of the RFP to guide the roles and responsibilities of utility personnel. Proposed Framework, ¶III.H.8.b.

Further steps may be considered, as appropriate, such as the utility may establish internally a separate project team to undertake the evaluation, with no team member having any involvement with the utility self build option. Proposed Framework, ¶III.H.8.c.

Where the utility seeks to advance its proposed facilities (i.e., over those of other developers who may submit bids for its RFP), the proposal must be well-developed (i.e., to the point of providing information required to meet the requirements of its RFP) and capable of implementation. Proposed Framework, ¶III.H.9.

Bids submitted by affiliates shall be held to the same contractual standards as projects advanced by other bidders. Proposed Framework, ¶III.H.10.

Whenever the utility or its affiliate seeks to advance a project proposal (i.e., in competition with those offered by other bidders) in response to a need that is addressed by its RFP, an independent observer will monitor its competitive bidding process and will report on progress and results to the Commission. Any negotiations between a utility and its affiliate during the course of a solicitation process shall be closely monitored by the independent observer. Proposed Framework, ¶II.C.1. In particular, contract negotiations with affiliates shall be permitted, provided that such negotiations are closely monitored by an independent observer.

Proposed Framework, ¶III.G.2.

The guidelines to address self-dealing concerns were established while keeping in mind that establishing additional requirements would result in a significant investment in time, expense and resources. For example, in undertaking a competitive bidding process, utilities generally establish several internal project teams for the price analysis, non-price analysis and contract negotiations. This usually requires several analysts to undertake the pricing assessment as well as representatives from a number of departments within the HECO Companies to undertake the non-price analysis (e.g. financial analysis, environmental analysis, fuels, engineering, transmission system analysis, operations, siting/land, and legal). HECO FSOP, Exhibit II at 21.

If the utility is proposing a self-build option, available resources may be further limited, or even unavailable, if a separate project team is formed to undertake the bid evaluation, with no team member having any involvement in the utility self-build option. Small utilities, such as HECO, may be particularly constrained in their ability to dedicate the appropriate amount of resources to adequately staff the project teams required. In other words, there are not enough people with the specialized skills to divide into the specific functions needed to carry out bidding and evaluation responsibilities, while at the same time being excluded from carrying out their planning and evaluation responsibilities with respect to the utility's own projects. Such a resource problem has existed for larger utilities, such as Portland General Electric, which presented a challenge for dedicating the required level of staff to the process. HECO FSOP, Exhibit II at 21.

It would be very difficult for the HECO Companies to come up with a sufficient number of qualified employees to staff two separate teams (i.e., a self-build project team and a competitive bidding evaluation team). The HECO Companies currently employ a minimum amount of people to manage the workloads under the current processes. There is a small group of people who manage power purchase, but they have to rely on outside legal and consulting expertise to manage their workloads. The HECO Companies' planning staff members are involved in long-range planning processes, IRP planning processes, power purchase contract negotiations and avoided cost calculations; they do this for the three different systems, HECO, MECO, and HELCO, where the operations vary significantly. Because of the dependence of small island systems on the firm capacity requirements, the processes for power purchase contracts have to be much more rigorous because the HECO Companies cannot afford a misstep that ultimately results in not having enough capacity on the system. Therefore, the HECO Companies in all probability would have to increase staff substantially to manage a complex competitive bidding process. Tr. (12/12) at 218-19 (Simmons).

If the HECO Companies had to increase their staff, it could be difficult to find qualified people. In fact, the HECO Companies are having a difficult time now filling positions that occur through normal attrition such as retirements or people leaving to explore other opportunities. There is a shortage of skilled staff in many different areas including engineering. Utility planning is not a field in which it is easy to find people who have experience and knowledge in running complex models. There is a small pool of available candidates, and the Company anticipates a shortage of qualified individuals. Tr. (12/12) at 220 (Simmons).

The HECO Companies could retain consultants to assist its staff in complying with competitive bidding requirements. However, relying on consultants entails problems as well, namely the difficulty in bringing consultants up to speed regarding technical issues that are peculiar to an isolated island system. Tr. (12/12) at 222-23 (Simmons).

The HECO Companies simply do not have enough facilities to house separate self-build and bid evaluation teams in separate buildings. Barring any oral or written communications between members of self-build and bid evaluation teams would be a major burden on the HECO Companies because, as noted above, HECO employees on such teams must also carry out their regular job duties and to do so must communicate with each other.

Moreover, a prohibition on communication is unnecessary. First, the independent observer will monitor communications between the bid evaluation team and the self-build team just as he or she will monitor communications with any other bidder. Proposed Framework, ¶III.H.7. Second, communications between team members will be regulated by a Code of Conduct. Proposed Framework, ¶III.H.8.b. The same considerations apply to the suggestion in Commission Outline III.A.2.d(3)(d), namely requiring all bid information to be kept on a separate computer system. Confidentiality of bid information could be maintained through appropriate document management safeguards and access privileges. Requests for clarification of the RFP from the self-build team can be handled in the same manner as a request from any other bidder. (Commission Outline III.A.2.d(3)(e)).

Regarding Commission Outline III.A.2.d(3)(f), the integrity of the competitive bidding process would be protected adequately if an officer of the utility has the authority to enforce the Code of Conduct and if each employee on each team certifies that he or she has reviewed the Code of Conduct and agrees to comply with its terms.

3. Utility affiliate participation

a. Assume the Commission will not require the utility to use an affiliate for the utility's self-build obligation. These questions explore the extent to which a utility affiliate may participate in the bidding as a third-party competitor.

b. What are the limits, if any, on the Commission's authority to permit, prohibit or condition a utility affiliate's participation in a competitive bid?

c. Assume the Commission has legal authority to permit, prohibit or condition a utility affiliate's participation.
d. Should the Commission permit a utility affiliate to bid?
e. Assume the Commission will permit a utility affiliate to bid, provided there is a code of conduct. What elements should the code contain?
f. What changes are necessary, in the relationship between the affiliate and the HECO utilities, to make the relationship arm's-length?

<u>Response</u>

Regarding Commission Outline III.A.3.b, the Commission's authority to permit, prohibit or condition a utility affiliate's participation in a competitive bid process would be limited by federal law (e.g., PURPA). For example the Commission could not deny a right to an entity that is granted by PURPA.

The Commission should permit a utility affiliate to bid. From the HECO Companies' perspective, they want to have the option of competing in the bid process through an affiliate separate from its self-build option. It is difficult to foresee future circumstances as to the best mechanism or corporate structure to bid into a particular RFP. The HECO Companies want to have the flexibility to make those determinations at a point in which it could best make them. Tr. (12/13) at 499-500 (Roose).

With respect to Commission Outline III.A.3.d through III.A.3.f, please refer to the response to III.A.2.d, above, which discussed when a utility's self-build project is involved. As discussed in that section, such safeguards would also apply to a utility affiliate project.

4. Access to generating sites
a. Where the Commission has determined that a particular site has unique attributes that are competitively significant, such that denial of bidder access will impede effective competition, should the Commission require the utility to make its undeveloped generation sites available to bidders?
b. Assume the Commission requires the utility to make its undeveloped generation sites available to bidders.
(1) Should the price be book cost or market value?

(2) If market value, assume the Commission finds that negotiations between the utility and the bidder will not be productive due to the utility's control of a competitively significant site. What will be the most efficient process for determining the price?
(3) If market value, what should be done with the gain if market value exceeds book?
(4) What actions should the Commission take to minimize or eliminate the following problems?
(a) reduction in the utility's ability to carry out parallel planning
(b) risk that the utility would incur liability risk associated with the bidder's option
(c) other
(5) Should competitive bidding of utility sites be limited to turnkey projects?

Response

The Commission should not require a utility to make its undeveloped generation sites available to bidders. Under the Proposed Framework, the utility may choose to offer one or several utility-owned and/or controlled sites to bidders in a competitive bidding process. Proposed Framework, ¶ II.A.3.

The Proposed Framework provides that the question of whether utility-owned and/or controlled sites will be made available to bidders should be determined on a case-by-case basis before an RFP is issued, and should include consideration of factors such as:

(1) The anticipated specific non-technical terms of potential proposals. An example of a factor that would need to be examined is whether benefits would be expected from a "turnkey" project that the utility would or may eventually own and operate. Proposed Framework, ¶ II.A.4.a.

(2) The feasibility of the installation. Examples of the factors that may need to be examined in order to evaluate the feasibility of the installation may include, but would not be limited to the following: (i) Specific physical and technical parameters of anticipated non-utility installations, such as the technology that may be installed, space and land area requirements,

topographic, slope and geotechnical constraints, fuel logistics, water requirements, number of site personnel, access requirements, waste and emissions from operations, noise profile, electrical interconnection requirements, and physical profile; and (ii) How the operation, maintenance and construction of each installation would affect factors such as security at the site, land ownership issues, land use and permit considerations (e.g., compatibility of the proposed development with present and planned land uses), existing and new environmental permits and licenses, impact on operations and maintenance of existing and future facilities, impact to the surrounding community, change in zoning permit conditions, and safety of utility personnel. Proposed Framework, ¶ II.A.4.b.

(3) The utility's anticipated future use of the site. Examples of why it may be beneficial for the utility to maintain site control may include, but would not be limited to the following: (i) to ensure power generation resources can be constructed to meet system reliability requirements, (ii) to retain flexibility for the utility to perform crucial parallel planning for a utility owned option to backup the unfulfilled commitments, if any, of third-party developers of generation, and (iii) to retain the flexibility for the utility to acquire the unique efficiency gains of combined-cycle conversions and repowering projects of existing utility simple-cycle combustion turbines and steam fired generating facilities, respectively. Proposed Framework, ¶ II.A.4.c.

Discussion

As indicated above, the question of whether should the Commission require the utility to make its undeveloped generation sites available to bidders, should include consideration of factors such as (1) the anticipated specific non-technical terms of potential proposals, (2) the feasibility of the installation and (3) the utility's anticipated future use of the site.

In addition to these factors, there are other reasons why the decision to offer undeveloped utility sites to bidders should be reviewed on a case-by-case basis with the final decision being made by the utility. An issue of primary concern is reliability. Utility-controlled sites are valuable assets that have been secured to benefit the customers over the long term. To ensure long-term reliability of supply, it would be beneficial for the utility to maintain site control to ensure power generation resources could be constructed to meet system reliability requirements. This is particularly true in Hawaii, where the number of sites that are available to site new generation are limited. See response to PUC-IR-53.

A concern that bears directly on reliability is that offering utility-controlled sites may reduce the flexibility of the utility to perform crucial parallel planning[24] for a utility-owned option to backup the unfulfilled commitments of IPP developers of generation. Hawaii utilities do not have the option to acquire power from other jurisdictions, or even other islands. See response to PUC-IR-53. A project developer's default could occur at any time, so parallel planning may extend well into the development process. If the site was made available for the developer's use, that could largely preclude the utility from utilizing that site for its parallel planning. In other words, the utility would not be able to carry out actual physical activities on the site because the winning bidder would be trying to do its development work at the same site. Tr. (12/14) at 635 (Roose). In particular, the utility would be significantly disadvantaged because it would not have been able to secure permits and water rights while it was off the land. Tr. (12/14) at 637-38 (Roose). As a practical matter, in order to carry out parallel planning in the context where the utility has turned over its site to the winning bidder, the parallel planning would have to occur on some other site. Tr. (12/16) at 641 (Roose).

Further, making a utility site available to bidders could also have an adverse impact on

[24] Parallel planning is discussed in detail in the response to Commission Outline II.A.2 and 3.

the utility's contingency plan.[25] Taking the Campbell Industrial Park site as an example, there is a second combustion turbine which would be the contingency measure if load growth increases faster than anticipated. Once the site is turned over to the developer, HECO has lost the ability to implement its contingency plan for accelerated load growth. Tr. (12/14) at 640 (Williams).

Moreover, offering utility-controlled sites may reduce the full value hoped to be gained in a competitive solicitation process. Bidders are not encouraged to develop creative options to meet Hawaii's needs, but instead will be more likely to select the utility site possibly limiting the range of resource options bid. For example, a pumped storage hydro developer may decide not to bid if a utility-controlled site located in Campbell Industrial Park was made available in the RFP. See response to PUC-IR-53.

Sites acquired by the utility are not fungible. They are not simply held in inventory for some future, undefined purpose. Historically, the IRP plans have identified resources that are needed within the 20-year planning process. The utility either has existing power plant sites which it expects to be able to expand or a need for additional sites on which to potentially locate generation. In some instances, the utility may be considering expanding an existing site, in others, looking at a new site. Tr. (12/14) at 622.

The HECO Companies' acquisition of sites normally is tied to a specific capacity plant. There is a presumption that a utility is not going to hold a site for future use for more than ten years without it being excluded from rate base, although that presumption can be overcome. The HECO Companies are seeing a planning process for future generation that may take ten years to install a new unit. Tr. (12/14) at 623.

Sites in which power plants can be located are valuable as there are numerous permitting

[25] Contingency planning is discussed in detail in the response to Commission Outline II.A.2 and 3.

and approval processes (e.g., air, water, land use) that must be successfully completed before a power plant can be located at the site. The HECO Companies may need to start certain permitting processes in order to be able to site power plants on its properties in the future, and even existing sites may become unavailable in the future because some of the air quality requirements have changed or the type of generation the utility now wants to site cannot be located there because of these other permitting restrictions. Tr. (12/14) at 622 (Williams).

In addition to the concerns described above, there are legal concerns with the utility being required to offer its site to a bidder. There are questions as to whether the Commission has the legal authority to impose such a requirement. There is no explicit authority to require the utility to dispose of its site. Even if the basis was simply to foster competition, that that would be an insufficient because the regulation of public utility scheme does not contemplate that the purpose of that scheme is to foster competition. There is no authority for the Commission to order the utility to dispose of its property, which, in effect, is what it would be doing. Moreover, the Commission cannot condemn the utility's property. Tr. (12/16) at 1099-1100. This is subject is discussed further in the "Other Jurisdictions" section below.

There may also be complex legal issues associated with the sale or lease of a utility-controlled site, such as ensuring that the bidder and not the utility absorbs any environmental liability associated with the site. See response to PUC-IR-53.

Regarding Commission Outline III.A.4.b(1), (2) (3) and (4)(b) dealing with pricing utility sites at book value versus market value and the risk of liability to the utility, as previously discussed, while the utility may voluntarily offer its sites to bidders under certain circumstances, the utility cannot be required to offer its sites to the bidders. It is not practical to develop meaningful responses to the questions posed at this time as the responses are fact-specific and depend upon the circumstances involved in the situation. The valuation of utility sites and the financial consequences of transferring sites to third parties may be determined by accounting rules, tax laws and regulations and other factors that are beyond the scope or control of a competitive bidding framework.

Regarding the risk of liability resulting from the bidder's option, the PPA or other contract for the selected source of generation should contain provisions that properly allocate risks among the parties in light of the circumstances. Proposed Framework, ¶III.C.1. For example, the utility may require hold harmless and/or indemnification provisions from bidders.

Other Jurisdictions

Mr. Oliver has seen the issue of making utility sites available come up in some other IRP processes in which he has been involved. However, he is not aware of any cases on the mainland where the utilities have been required to offer a site. Some have offered sites for third-party bids, but most have not. The general situation on the mainland is that it is at the discretion of the utility to make that determination. Tr. (12/14) at 658 (Oliver).

The issue came up in Oregon where the commission staff reviewed a recommendation by independent power producers that they be allowed to submit bids to construct a resource at the utility's site. The commission staff questioned the Oregon Department of Justice ("DOJ") "whether the Commission has the legal authority to require the investor-owned electric utilities to offer their site locations for development by independent power producers. Staff indicated that utility expenses associated with the acquisition and maintenance of site locations is normally excluded from the utility's revenue requirement. DOJ advised commission staff that it is concerned that there are legal impediments to implementing the [IPPs] recommendation." In the Matter of an Investigation Regarding Competitive Bidding, Public Utility Commission of

Oregon, Docket. No. UM 1182, Staff's Reply Comments, at 7 (October 21, 2005). See also, Tr. (12/14) at 658-59 (Oliver).

In Florida, the issue was the subject of extensive analysis in In re: Proposed revisions to Rule 25-22.082, F.A.C., Selection of Generating Capacity, Florida Public Service Commission, Docket No. 020398-EQ.

In that proceeding, the following proposed rule, among others, was under consideration:

> A public utility shall allow participants to construct an electric generating facility on the public utility's property. Any fees to be paid by the participant to the public utility for constructing on the public utility's property shall be included as a benefit to the public utility's ratepayers in the cost-effectiveness analysis of the participant's proposal and shall be credited to the public utility's capacity recovery clause.

The investor-owned utilities that were parties to that proceeding strongly opposed the draft rule. They argued that allowing competitors to site facilities on utility property was a per se "taking" of private property, that the proposed rule lacked a public use or purpose for the taking, and that the proposed rule did not provide for adequate compensation to utilities for the taking. In particular, the IOUs argued that:

> The United States Supreme Court has long held that "the property of a public utility, although devoted to the public service and impressed with a public interest, is still private property and neither the corpus of that property nor the use thereof constitutionally can be taken for a compulsory price which falls below the measure of just compensation."

Comments Of Utilities Regarding Potential Revisions To Rule 25-22.082, filed March 15, 2002, at p. 29, citing United Rys. & Elec. Co. v. West, 280 U.S. 234,249 (1930), overruled on other grounds by Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

The Florida draft rule was revised as follows:

> A participant may submit and the public utility shall evaluate

> proposals to collocate the participant's proposed generating facility and to utilize the common facilities at a public utility's existing power plant site. The public utility may require compensation for such collocation and use of its common facilities.

The IOUs opposed the revised draft rule and argued that the commission lacked the statutory authority "to require a utility to consider opening its property to an unrelated entity to provide generating capacity, even if that approach may be -- in the view of the Commission -- the most cost-effective alternative." They also reasserted their argument that the proposed rule could, "operate as an unconstitutional taking of utility property under the federal and state constitutions." The IOU's pointed out that the commission could not avoid the constitutional problem by indirect action in a ratemaking proceeding, "[I]f the Commission denies cost recovery because a utility did not allow a competitor to locate facilities on utility-owned property, it is effectively requiring a utility to suffer a taking of its property." Comments of Investor-Owned Utilities, filed June 28, 2002, at 17-18.

The proposed rule requiring that utility sites be made available to IPPs in a competitive bidding process was dropped from the Florida Public Service Commission's Order Adopting Changes To The Proposed Amendments Of Rule 25-22.082, Florida Administrative Code, dated January 27, 2003.

5. Access to transmission

a. Should the Commission require a written policy on procedures for interconnection and transmission upgrades, to ensure comparable treatment among bidders, and between independent bidders and the utility's self-build option?

b. Assume the Commission will require a written policy on procedures for interconnection and transmission upgrades, to ensure comparable treatment among bidders, and between independent bidders and the utility's self-build option. What elements should the policy contain? Consider:

(1) advance identification of zones reflecting different levels of interconnection cost and transmission upgrade cost

(2) a formal queuing process that ensures nondiscriminatory treatment of all requests for interconnection, upgrades and studies thereof

(3) a means of minimizing the cost of studies by bundling different requests into a single study
(4) information about capacity, operations, maintenance and expansion plans relating to the transmission and distribution system?
(5) other

c. What form should the Commission's requirement take? Consider:
(1) Commission-issued rules
(2) utility tariff
(3) Commission-issued framework
(4) other

d. Should interconnection costs (costs necessary to interconnect the generator with the utility's transmission system) be assigned directly to the generator, and therefore not affect cost comparisons among the bids?

e. What treatment should the Commission require for transmission upgrade costs? Consider these possibilities:
(1) the upgrade would never have been built for utility system purposes, and --
(a) provides no cost or reliability benefit to the utility's customers
(b) does provide cost or reliability benefit to the utility's customers
(2) upgrade would have been built for utility system purposes, five years later than the IPP in-service date; and, during the five-year wait --
(a) provides no cost or reliability benefit to the utility's customers
(b) does provide cost or reliability benefit to the utility's customers

f. What measures should the Commission employ to ensure that the utility does not discriminate against IPPs in carrying out transmission studies and allocating transmission upgrade costs?
(1) Should the interconnection and transmission studies involving IPPs be --
(a) performed by an independent entity and
(b) be approved by the Commission?
(2) If the utility does .the study, should the study be --
(a) evaluated by an independent entity and
(b) approved by the Commission?

<u>Response</u>

The Proposed Framework provides that "[i]n evaluating competing proposals, all relevant incremental costs to the electric utility and its ratepayers should be considered (e.g., these may include transmission costs and system impacts, and the reasonably foreseeable balance sheet and related financial impacts of competing proposals)." Proposed Framework ¶III.D.6.

With respect to Commission Outline III.A.5.a, while the Commission may require a written policy on procedures for interconnection and transmission upgrades, such a requirement should not be necessary as such procedures (including applicable transmission planning criteria, transmission design standards, and substation design standards) will be set forth in the utility's RFP (which under the Proposed Framework, the RFP is provided to the Commission for its review before the RFP is issued, and the Commission does have the ability to stop the RFP from being issued).

With respect to this question, in general, the RFP should discuss (1) who will be responsible for the cost to interconnect the bidder's facility to the utility system, (2) who will be responsible for the transmission system upgrade costs, (3) how information concerning the utility's transmission system will be provided to bidders, (4) the process for determining the interconnection costs (i.e., the interconnection requirements study ("IRS") process), the order in which IRS's will be performed (generally, it is a first-come first-served concept), and who is responsible for the cost of the IRS,[26] (5) the utility's "base" transmission plan so that bidders will have a general high level understanding of the utility's transmission system capabilities and where it may be easier and harder (from a transmission planning system) to add new generation,[27] and (6) the process to allocate the benefits and costs of the transmission system upgrades[28] . This type of information should be provided as part of the RFP so that bidders will have an understanding as to the process that will be conducted.

With respect to Commission Outline III.A.5.b(1), (2), and (4), please see the above discussion. As to whether costs could be minimized by "bundling different requests into a single study" (Commission Outline III.A.5.b(3)), in general this process would not result in cost savings. IRS are project-specific studies. Analyses (e.g., interconnection requirements, cost of

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26 See e.g., Tr. (12/14) at 676-82 (Simmons).
27 See e.g., Tr. (12/15) at 951-53 (Roose).
28 See e.g., Tr. (12/15) at 952-54 (Roose).

the interconnection requirements, transmission system upgrades necessary, cost of the necessary transmission system upgrades, line loss calculations) will have to be conducted based on the specifics of each proposed project (e.g., size, location, technology, timing, etc.). Unless there were two or more projects being proposed in the same general area, with the same technology and size, and for the same time period, there may be little advantage to bundling the projects in order to cut down the costs.

As to whether information can be provided to bidders concerning the distribution system (Commission Outline III.A.5.b(4)), it may not be possible to provide that type of information as the HECO Companies generally do not have that type of information for the distribution system. Distribution system additions are generally driven by the addition of new customers (e.g., new residential developments) which the utility does not control nor forecast with reasonable accuracy for more than a couple of years in advance. So it will be impractical to provide that type of information for the distribution system.

With respect to Commission Outline III.A.5.c, in the event the Commission will require a written policy on procedures for interconnection and transmission upgrades, such a requirement should be included in the Framework as one of the guidelines. If the Commission decides to use this approach, the proposed guideline should follow the same approach the Stipulating Parties followed in developing the guidelines included in the Proposed Framework (i.e., the guideline should be flexible enough to permit tailoring the process to specific circumstances, yet specific enough to avoid after-the-fact determinations of fundamental process matters[29]).

With respect to Commission Outline III.A.5.d, the "interconnection costs (costs necessary

[29] Stipulation Regarding Proposed Competitive Bidding Framework, filed May 22, 2006 at 4.

to interconnect the generator with the utility's transmission system)" should be assigned directly to the generator. Such treatment is consistent with the treatment of interconnection costs in the Commission's Standards for Small Power Production and Cogeneration (Hawaii Administrative Rules Title 6, Chapter 74).

The interconnection costs will be included as part of the cost of the projects when evaluating the projects. The interconnection costs will be included as part of the utility's self-build option. In all likelihood, for IPPs, their price will reflect its interconnection cost Tr. (12/15) at 947-48. If the IPP's price did not reflect its interconnection cost, in effect, the IPP will be providing that part of the project for "free" and will impact the profitability and financeability of the project.

With respect to Commission Outline III.A.5.e(1)(a), in the situation where the transmission system upgrade would "never have been built for utility system purposes and provides no cost or reliability benefit to the utility's customers", then all of the transmission system upgrade costs should be allocated to the bidder. (This response presumes that "no cost benefit to the utility's customers" includes no line loss savings and no transmission capacity benefits (e.g., does not defer or displace transmission additions planned in the future).)

Such treatment is reasonable given that the transmission system upgrades (1) would not have occurred but for the bidder's project, and (2) do not provide any "cost or reliability benefit to the utility's customers".

With respect to Commission Outline III.A.5.e(1)(b), in the situation where the transmission system upgrade "would never have been built for utility system purposes and does provide cost or reliability benefit to the utility's customers", then a portion of the transmission system upgrade costs should be allocated to the bidder's project (and a portion of the transmission system upgrade costs should be allocated to the utility). In general, in determining the benefits to the utility's customers of a transmission system upgrade, the utility would examine what transmission system additions have been deferred or displaced by the transmission system upgrade, calculate a dollar value of that deferral or displacement, and credit the bidder for that deferral or displacement value. In addition, the utility would also calculate any change in line losses resulting from the transmission system upgrade, and if there was a reduction in line losses, the savings would be calculated and credited to the bidder. See Tr. (12/15) 951-54 (Roose).[30]

With respect to Commission Outline III.A.5.e(2)(a), in the situation where the transmission system "upgrade would have been built for utility system purposes, five years later than the IPP in-service date; and, during the five-year wait provides no cost or reliability benefit to the utility's customers", then the bidder would be allocated the cost of moving up the date of the transmission system upgrade (i.e., the cost of placing the upgrade in service five years earlier). See Tr. (12/15) at 954 (Roose). In this question, an assumption is that there are no benefits to the utility's customers of the transmission system upgrades, so there is no offset to the cost allocated to the bidder.

With respect to Commission Outline III.A.5.e(2)(b), in the situation where the transmission system "upgrade would have been built for utility system purposes, five years later than the IPP in-service date; and, during the five-year wait does provide cost or reliability benefit to the utility's customers", then, like the scenario in Commission Outline III.A.5.e(2)(a), the bidder would be allocated the cost of moving up the date that the transmission system upgrade was placed in service. However, since the assumption is that there is some type of benefit to the

[30] In general, the HECO Companies do not quantify "reliability" benefits associated with transmission system upgrades.

utility's customers of the transmission system upgrades, the calculated benefit of the upgrade would be credited to the bidder (e.g., line loss savings).

It should be noted that depending upon the type of resource being proposed by a bidder, its size, and the location of the proposed facility relative to the utility grid and load centers, even with the addition of transmission system upgrades either triggered by or advanced by the project, line losses may increase as a result of the addition of the project. Under such cases, this "negative line loss savings" would be assessed to the bidder.

With respect to Commission Outline III.A.5.f, the IRS should be conducted by the utility (or conducted by a third-party entity selected by the utility). One of the benefits to having the utility conduct the IRS is that the utility is most familiar with its transmission system. This is the procedure that is currently in place when the HECO Companies negotiate with IPPs. See Tr. (12/14) 676-78 (Simmons). As discussed at the panel hearing, in order to have IRS's conducted in a timely fashion, there have been occasions when HECO has had all or parts of an IRS conducted by a third-party due to "manpower" constraints. However, even when portions of an IRS is conducted by a third-party, it still takes time to complete the IRS because the entity is not as familiar with the utility's system and need to become familiar with the particular system.

The HECO Companies are concerned about having a requirement that the utility conducted IRS be evaluated by an independent entity and approved by the Commission. This could lengthen the process to complete the RFP and delay the time to install the generation. IRS are by their very nature, very detailed and contain a voluminous amount of technical data. If an independent entity were to evaluate an IRS, the entity would first have to become familiar with the utility's system, and then start to review the IRS. This process could take a long time.

An alternative approach is the one that is similar to the one currently in place for QFs. If the bidder has questions concerning the IRS, then the bidder can try to have its questions addressed by the utility on an informal basis (with the help of the independent observer if there is one involved in the RFP). In the event that the bidder's questions are not addressed on an informal basis, then the bidder can take its questions to the Commission to be addressed.

This way the Commission only becomes involved if the bidder has questions about the IRS that cannot be resolved on an informal basis with the utility. This should help to save time in the RFP process and only have the Commission involved in IRS in which there are differences between the parties. This process is included in the dispute resolution section of the Proposed Framework (¶IV).

III.B. Independent Entity Roles

1. When is an independent entity necessary?
a. when the utility presents a self-build option?
Question: when, if ever, would the utility not present a self-build option?
b. when a utility affiliate is bidding?

Response

Section III.B of the Commission's Outline refers to an "independent entity." The Company prefers the term independent observer. It is more descriptive of the function of this position and is the term used in the Proposed Framework filed by the parties to this proceeding on May 22, 2006.

An independent observer need not be retained for each and every RFP process. HECO FSOP, Ex. II, p. 12; Tr. (12/12) at 144-45 (Roose). The independent observer should only be used when the utility or its affiliate seeks to advance a project proposal so that the independent observer can monitor and report on the evaluation and selection process and respond to concerns (if any) involving the selection of the winning project. In situations where the utility or its affiliate is not a bidder in the competitive bidding process there should not be similar concerns involving the selection of the winning project and therefore an independent observer should not be necessary.

Regarding the question in III.B.1.a, above, "when, if ever, would the utility not present a self-build option?", please refer to the Company's responses to the questions in Commission Outline II.A.2.

<u>Framework</u>

If proposed utility self-build facilities or other utility-owned facilities (e.g., turnkey facilities), or facilities owned by an affiliate of the host utility, are to be compared against IPP proposals obtained through an RFP process, the electric utility should retain an independent observer. Proposed Framework, Section II.C.1, III.H.7.

2. What roles should the independent entity have? Consider:

- *a. administrative roles*
  - *(1) manage the correspondence between the utility and bidders*
  - *(2) other*
- *b. advisory roles*
  - *(1) certify to the Commission that each of the following utility proposals was based on a fair process and will promote fair decisionmaking:*
    - *(a) pre-qualification criteria*
    - *(b) IRP*
    - *(c) RFP*
    - *(d) model PPA to be attached to the RFP*
    - *(e) code of conduct*
    - *(f) self-build bid to be included with the RFP*
    - *(g) selection criteria*
    - *(h) final decision to purchase power or proceed with self-build option*
    - *(i) other*
  - *(2) advise the utility on the fairness of utility decisionmaking during, and with respect to, each of the utility actions listed in the preceding question*
  - *(3) advise the Commission on the fairness of utility decisionmaking during, and with respect to, each of the utility actions listed in the second preceding question*
  - *(4) resolve disputes that arise during --*

(a) the procurement process
(b) post-selection negotiations
(5) report violations of any procurement rules
(6) after the procurement decision, provide the Commission with --
(a) an overall assessment of whether the goals of the RFP were achieved, including solicitation of sufficient, competitive bids were received and the results of the RFP were unbiased; and
(b) recommendations for improving future competitive bidding processes
(7) Question: Is an independent entity certification a certification of fairness only, or is it also a certification of prudence?

c. decisionmaking roles
(1) disqualify bidders
(2) require rebidding where there are flaws in the procurement process
(3) amend a particular stage of the procurement process to cure flaws
(4) determine bid evaluation criteria
(5) decide disputes

Response

Responding to Commission Outline III.B.2, the Company favors advisory and administrative roles for an independent observer, but not a decision-making role. Some of the appropriate roles of the independent observer are set forth in the Proposed Framework, the pertinent portions of which are referred to below.

With respect to the decision-making roles suggested in Commission Outline III.B.2.c, as further discussed below, it is the position of the Company that acting as a decision-maker is beyond the function of an independent observer.

With regard to the question in Commission Outline III.B.2.b(7), as further discussed below, it is the position of the Company that, when the independent observer validates the fairness of the process, the independent observer is not also validating the prudence of the process.

Framework

If proposed utility self-build facilities or other utility-owned facilities (e.g., turnkey facilities), or facilities owned by an affiliate of the host utility, are to be compared against IPP proposals obtained through an RFP process, the electric utility should retain an independent observer to monitor the utility's conduct of its RFP process, advise the utility if there are any fairness issues, and report to the Commission at various steps of the process. Specific tasks to be performed by the independent observer will be identified by the utility in the utility's proposed RFP documentation. Proposed Framework, paragraph III.H.7.

In general, the independent observer will review and track the utility's execution of the RFP process to ascertain that no undue preference is given to an affiliate and its bids, or to self-build or other utility-owned facilities. This may include, to the extent necessary, (a) reviewing the draft RFP and the utility's evaluation of bids, monitoring communications (and communications protocols) with bidders, (b) monitoring adherence to codes of conduct; and monitoring contract negotiations with bidders, (c) validating the utility's evaluation of affiliate bids, and self-build or other utility-owned facilities, and (d) validating the utility's evaluation of an appropriate number of other bids, at the discretion of the independent observer and the Commission. Proposed Framework, paragraph III.H.7.

The utility may provide the independent observer with the utility's evaluation of the unique risks and advantages associated with utility self build or other utility-owned facilities, including the regulatory treatment of construction cost variances (both underages and overages) and costs related to equipment performance, contract terms offered to or required of bidders that affect the allocation of risks, and other risks and advantages of utility self-build or other utility-owned projects to consumers. The independent observer may validate the criteria used to evaluate affiliate bids and self-build or other utility-owned facilities, and the evaluation of affiliate bids and self-build or other utility-owned facilities. In order to do this, the utility (in conjunction with the independent observer) should propose methods for making fair comparisons (considering both costs and risks) between the utility owned or self build facilities and third party facilities. Such a comparison between self-build or other utility-owned facilities and IPP facilities may include modeling likely variation in construction costs, plant efficiency, plant outages, and/or operation and maintenance costs and assigning a risk premium to the self-build or other utility-owned facilities, and the likely impact of IPP proposals on the utility's capital structure. Proposed Framework, paragraph III.H.7. See also, Proposed Framework, paragraph II.C.1.

Any negotiations between a utility and its affiliate during the course of a solicitation process shall be closely monitored by the independent observer. Proposed Framework, paragraph II.C.1.

In the event the utility receives non-conforming bids in response to its RFP, the independent observer may advise the utility whether the bidder should be given additional time to remedy its non-conformity or whether the utility should decline to consider any bid that is non-conforming. Proposed Framework, paragraph III.D.6.

The independent observer may work with the utility and bidders to resolve disputes. Proposed Framework, paragraph IV.

In the event the utility and the independent observer disagree regarding matters that arise during the RFP process, the utility will develop, as part of the RFP design process, procedures to be included in the RFP documentation by which the utility may present to the Commission, for review and resolution, positions that differ from those of the independent observer (i.e., in the event the independent observer makes any representations to the Commission with which the utility does not agree). Proposed Framework, paragraph II.C.4.

Discussion

With respect to the decision-making roles suggested in Commission Outline III.B.2.c, it is the position of the Company that acting as a decision-maker is beyond the function of an independent observer. The Company's competitive bidding consultant, Wayne Oliver, testified at the hearing in this matter that the decision-making role is viewed as belonging to the utility. Mr. Oliver was not aware of any conditions in which an independent observer has made decisions on resource selection or reopening an RFP or anything of that sort. Tr. (12/13) at 531 (Oliver).

Mr. Oliver's observations are consistent with the comment of investor-owned utilities ("IOUs") in a proceeding before the Florida Public Service Commission, *In re: Proposed revisions to Rule 25-22.082, F.A.C., Selection of Generating Capacity*, Docket No. 020398-EQ. In a letter to the Chairman of the Commission dated September 6, 2002, the IOUs noted:

> The Commission has recognized in the past that a provision for third-party evaluation of bids and selection of the project shifts the responsibility for capacity additions to an unregulated entity. This shift would be contrary to the statutory obligation of the IOUs to provide adequate and reliable service to their customers. Part of an IOU's statutory obligation to serve is to be responsible for and to justify its selection in the bidding process.

The revised rules approved by the Florida Commission in that proceeding did not provide for evaluation of proposals by a third-party.

With regard to the question in Commission Outline III.B.2.b(7), it is the position of the Company that, when the independent observer validates the fairness of the process, the independent observer is not also validating the prudence of the process. The independent observer's role is to ensure that the process is fair and equitable. The independent observer does not state which decisions made during the process were prudent and which were not. The independent observer's validation of the objectivity of the process is not equivalent to a validation of the prudence of the process. However, in some of the competitive bidding processes in which Mr. Oliver has been involved as an independent observer, his report to the regulatory body on the fairness of the process has been acknowledged by the regulatory body as being one of the reasons why it approved the proposed contract. Having an independent observer making sure the process is fair can help in making a determination that it is prudent. See Tr. (12/14) at 725-28 (Oliver).

The Company's consultant, Wayne Oliver, testified that the independent observer should try to resolve disputes jointly with the utility, and if that is not successful, the independent observer should talk with the Commission. Tr. (12/15) at 819 (Oliver).

3. Who should select the independent entity, and by what process? Consider:

- *a. Commission approves list of candidates, utility selects from the list*
- *b. Utility presents approves list of candidates, Commission selects from the list*
- *c. Utility and Commission jointly create list of candidates (list created by each proposing a list from which the other may delete names); then --*
    - *(1) utility selects from the list*
    - *(2) Commission selects from the list, or*
    - *(3) both utility and Commission approve selection*

4. To whom should the independent entity be contractually accountable -- Commission, utility or both?

- *a. Commission*
- *b. utility*
- *c. both*

5. Who should pay the costs of the independent entity? Consider:

- *a. Commission, with costs recovered from the utility who then recovers costs from ratepayers*
- *b. Utility, who then recovers costs from ratepayers*
- *c. Other*

Response

Commission Outline III.B.3 raises the issue of how the independent observer should be selected. The Stipulating Parties propose that the independent observer be selected through a process that involves some of the features from III.B.3 a through c. Under the Proposed Framework, the utility would (1) identify candidates for the independent observer position and may also consider candidates identified by the Commission, (2) present the list of candidates to the Commission for approval, and (3) select the independent observer from the list of candidates.

As to Commission Outline III.B.4, the utility, rather than the Commission, should enter into a contract with the Independent Observer. However, the independent observer would report to and consult with both the utility and the Commission.

With respect to Commission Outline III.B.5, the costs of the Independent Observer should be paid by bidders' fees. If the independent observer's costs exceed the amount of the bidders' fees, the balance could be paid by the winning bidder or the utility (which in turn would recover the costs from its ratepayers).

Framework

The Proposed Framework provides that, if an independent observer is to be used, the utility may (a) identify qualified candidates for the role of independent observer (and also may consider qualified candidates identified by the Commission), (b) seek Commission approval of its final list of qualified candidates, and (c) select an independent observer from among qualified candidates. Proposed Framework, II.C.3.

Independent observers should be qualified for the tasks that they are to perform. This may require that they be knowledgeable about the unique characteristics and needs of small, non-interconnected island electric grids, and be aware of the unique challenges and operational requirements of such systems; have the necessary experience and familiarity with utility modeling capability, transmission system planning, operational characteristics, and other factors that affect project selection; have a working knowledge of common purchased power contract terms and conditions, and the purchased power contract negotiation process; be able to work effectively with the utility during the bid process; and be able to demonstrate impartiality. Proposed Framework, paragraphs II.C.2.a through e. The independent observer should be retained by the utility. Proposed Framework, paragraph III.H.7.

Discussion

Generally in RFP processes on the mainland, it is the utility that makes the decision to hire the independent observer. Mr. Oliver is aware of only two cases where the regulatory body has hired the independent observer (i.e., Georgia and Utah). In all other cases in which he has been involved, the utility has hired the independent observer. Specific rules in different states spell out whether the decision is made unilaterally by the utility or by the utility with review by the regulatory body. Tr. (12/14) at 565 (Oliver).

The utility, rather than the Commission, should enter into a contract with the Independent Observer. However, the independent observer would report to and consult with both the utility and the Commission. Tr. (12/14) at 570-71 (Roose).

Based on his experience in Utah, Mr. Oliver found that the process of being hired by the regulatory body may be somewhat more costly because of the requirements that are placed on the independent observer. However, generally, Mr. Oliver's firm generally is hired by the utility with the "blessing" of the regulatory body's staff or the staff being aware of the hiring. Tr. (12/12) at 171 (Oliver).

It is possible for an independent observer to report both to the utility and the regulatory body. For instance, Mr. Oliver's role in an RFP process in Louisiana was to act as an intermediary between Southwestern Electric Power Company and the Louisiana commission's staff. Mr. Oliver received comments from the utility and from the commission staff. In some cases, he agreed with what the utility proposed. In other cases, he did not and he reported that to the commission staff. It was basically a three-party arrangement. Mr. Oliver's role was to report to the staff and provide the utility with the best information about the process and what he thought was fair. The process in Oklahoma was similar. Tr. (12/14) at 568-69 (Oliver).

The independent observer's contract could contain a provision that the independent observer could be terminated on the request of the Commission. Tr. (12/14) at 570-71 (Roose).

The costs of the Independent Observer should be paid by bidders' fees. Tr. (12/14) at 564-65 (Roose). If the independent observer's costs exceed the amount of the bidders' fees, the balance could be paid by the winning bidder or the utility. Tr. (12/14) at 566 (Oliver).

III.C. Commission Roles

1. Which if any of the following roles should the Commission play?

a. approve utility proposals on --

(1) pre-qualification criteria
(2) IRP
(3) RFP
(4) model PPA to be attached to RFP
(5) code of conduct
(6) self-build bid to be included with the RFP
(7) selection criteria
(8) final decision to purchase power from a specific seller or proceed with self-build option

b. resolve disputes that arise during --

(1) the procurement process
(2) post-selection negotiations

c. other

Response and Framework

In general, the primary role of the Commission should be to ensure that each competitive bidding process conducted pursuant to the Competitive Bidding Framework is fair in its design and implementation, and to ensure that projects selected through competitive bidding processes are consistent with the utility's approved IRP Plan (unless otherwise justified). Proposed Framework, ¶II.B.1. The proposed specific roles of the Commission are discussed below.

The Commission would approve the IRP Plan. Proposed Framework, ¶¶ I.C.3 and II.B.1. It would also approve the final decision to purchase power from a specific seller or proceed with a self-build option. Proposed Framework, ¶ II.B.4. The Commission will review and approve the contracts that result from competitive bidding processes conducted pursuant to the Framework. The Commission may establish review processes that are appropriate to the specific circumstances of each solicitation, including the time constraints that apply to each commercial transaction. Proposed Framework, ¶II.B.4. If the electric utility's self-build or turnkey project is identified as superior to bid proposals, the utility would seek Commission approval in keeping with established capital project application review procedures. Proposed Framework, ¶II.B.5.

The remaining six categories in Commission Outline III.C.1.a, namely, pre-qualification criteria, RFP, PPA to attached to RFP, code of conduct (if the utility or its affiliate is bidding), self-build to be included with the RFP and selection criteria, all will be part of the RFP documentation. The utility will submit its final, proposed RFP to the Commission for its review. Proposed Framework, ¶III.B.4.f. The Commission will review each proposed RFP before it is issued, including the documentation that would accompany the RFP. Proposed Framework, ¶II.B.2. The utility will have the right to issue the RFP if the Commission does not direct the utility to do otherwise within 30 days of its having submitted its final, proposed RFP for review. Proposed Framework, ¶III.B.4.g.

The Commission should not approve the Request for Proposal documentation (i.e., the RFP, Response Package and proposed forms of power purchase agreements and other contracts).

With regard to Commission Outline III.C.1.b, whether the Commission should play a role in resolving disputes that arise during the procurement process or during post-selection negotiations, the Proposed Framework provides that the Commission will serve as an arbiter of last resort, after the utility, independent observer (if one is involved), and bidders have attempted to resolve any dispute or pending issue. The parties will be encouraged to seek to work cooperatively to resolve any dispute or pending issue, perhaps with the assistance of an independent observer. The utility may conduct informational meetings with the Commission and the Consumer Advocate to keep each apprised of issues that arise between or among the parties. Proposed Framework, ¶IV.

Discussion

Commission Approval of RFP

Any process requiring formal approval of the RFP before issuance (rather than an informal process permitting regulators to comment on the RFP) could substantially and needlessly delay an RFP process, and render it unworkable. The Commission would formally approve the IRP Plan, and any determination therein to conduct or not conduct an RFP process, and the proposed scope of the RFP process. The Commission also would formally approve the outcome of the RFP process (or other resource procurement process), whether the outcome was a utility-built or utility-owned facility or facilities, or an IPP-owned facility or facilities, or a combination thereof. Both processes will need to be expedited for the overall process to be workable – given the time required for detailed engineering, subcontractor contracting, permitting, equipment procurement and construction after the outcome is approved.

A synopsis of the way the issue of RFP review and "approval" evolved in a recent Florida proceeding to amend its resource procurement rule, which illustrates why such a seemingly simple matter is anything but simple, follows:

Florida PSC Proceeding

On February 7, 2002, the Florida Public Service Commission ("FPSC") held a workshop to consider revisions to its capacity selection rules and discuss a "strawman" version of proposed revisions that its staff prepared.

Comments were submitted jointly by Florida's four investor-owned utilities -- Gulf Power Company ("Gulf '), Tampa Electric Company ("TECO"), Florida Power Corporation ("FPC"), and Florida Power & Light ("FPL").

In its Order Initiating Rule Development, Order No. PSC-02-0723-PCO-E, issued May 28, 2002, in Docket No. 020398-EQ, the FPSC proposed changes to §25-22.082, F.A.C., Selection of Generating Capacity. In Order No. PSC-03-0133-FOF-EQ, issued January 27, 2003, the FPSC modified the proposed rule revisions, and issued the revisions as modified.

Staff's Proposed Amendments identified in handout (2/7/02)

FPSC staff's proposed amendment numbers 10, 11, and 12 stated:

> (10) The public utility shall conduct a meeting prior to the release of the RFP with potential participants to discuss the requirements of the RFP. The public utility shall also conduct a meeting within two weeks after the issuance of the RFP and prior to the submission of any proposals. The Office of Public Counsel and the Commission staff shall be notified in a timely manner of the date, time, and location of such meetings.
>
> (11) A potential participant who attended the public utility's post issuance meeting may file with the Commission specific objections to any terms of the

RFP within 10 days of the post issuance meeting. Failure to file objections within 10 days shall constitute a waiver of those objections. The Commission will address any objections to the terms of the RFP on an expedited basis.

(12) A minimum of 60 days shall be provided between the issuance of the RFP and the due date for proposals in response to the RFP.

IOU Memorandum (3/15/02)

The IOUs provided a number of comments on the staff's proposed amendments, including the following:

> Modifying the existing rule to create additional regulatory procedures and regulatory review that can give rise to challenges to the bidding process, will only further adversely affect the customers' best interests. Instituting front-end review of the RFP process will delay the overall process of adding capacity. Also, any regulatory proceeding creates an opportunity for time-consuming, wasteful litigation and delay. Further, appeals on the front end will add substantial delay.
>
> Persons will claim to be adversely affected by a decision of the Commission ruling on the propriety or impropriety of an RFP package. If the proposed RFP is disputed, the delay from ensuing litigation could take months or years.

Order Initiating Rule Development (5/28/02)

Section 10 of the order initiating rule development stated:

> (10) Any potential participant in the RFP may file comments with the Commission regarding any aspect of the RFP prior to the due date for proposals specified in the RFP. The Commission may take such action with respect to any comments filed as it deems appropriate.

IOU Comments (6/28/02)

The IOU provided comments regarding Section 10 of the order. The IOUs stated:

> Section (10), authorizing the Commission to act on comments, vests unbridled discretion in the Commission, poses potential constitutional problems, and would inject the opportunity for interminable delay and litigation.
>
> Section (10) of the draft rule allows any "potential participant" in a utility's RFP process to file comments with the Commission concerning "any aspect" of the RFP at any time before the due date for responses to the RFP. The Commission "may take such action with respect to any comments filed as it

deems appropriate."

Section (10) poses numerous problem[s], the greatest of which is the unbridled discretion it grants the Commission to take any action it "deems appropriate." A rule is an invalid exercise of delegated legislative authority if it "is vague, fails, to establish adequate standards for agency decisions, or vests unbridled discretion in the agency." § 120.52(8)(d), Fla. Stat. The final sentence of section (10) violates all of these provisions and provides solid grounds for invalidation of the rule by an Administrative Law Judge. If the Commission reviews the RFP in advance, it has no standards guiding its review. Moreover, the vague language raises potential concerns under the constitutional "void for vagueness" doctrine and under the separation of powers provision in article 11, section 3 of the Florida Constitution, which is implicated when agencies exercise "lawmaking" authority that is within the purview of the Legislature.

Order Proposing Revised Amendments (10/17/02)

Sections 11 and 12 of the order proposing revised amendments stated:

(11) A potential participant who attended the public utility's post-issuance meeting may file with the Commission specific objections to any terms of the RFP within 10 days of the post-issuance meeting. Failure to file objections within 10 days shall constitute a waiver of those objections. The Commission will address any objections to the terms of the RFP on an expedited basis.

(12) A minimum of 60 days shall be provided between the issuance of the RFP, and the due date for proposals in response to the RFP.

IOU Comments (11/15/02)

The IOUs submitted comments on the order proposing revised amendments. The IOUs stated:

The IOUs strongly urge the Commission to delete section (11). This section at first blush appeared to be a proposal the IOUs could live with, and the IOU group struggled to find proposed language that would make the timeframes workable and that would alleviate the extensive delays that would be created by this new point of entry. Ultimately, the group determined that this section could not be revised in a fashion that would avoid significant damage to the capacity addition process.

With proposed section (11) in the rule, participants objecting to the RFP would request a hearing, which would involve time-consuming discovery, retention of expert witnesses, and all the other costly trappings of full-blown litigation. That process could take months. If the Commission ultimately ordered revisions to an RFP, additional delays would be associated with making those changes.

Providing potential participants with an opportunity to challenge an RFP also would have the effect of making the pre-bid meeting adversarial, with the IPPs conducting "discovery" at that meeting to prepare their objections. The proposed rule does not limit the aspects of an RFP that can be challenged; thus, IOUs could be subjected to challenges from multiple parties on many different sections of the document. Addressing the myriad challenges and scheduling all of them for hearing could take many weeks. Ultimately, providing an opportunity to object to the RFP accomplishes nothing, as losing bidders might well later challenge the IOU's application of its RFP to their bids. Unsuccessful bidders will argue that they did not challenge the RFP on the front end because they had no way of knowing how the utility would ultimately apply its provisions. Thus, there would always be the opportunity for two rounds of litigation. The IOUs believe that proposed section (11) is not in the best interest of customers and should be deleted from the proposed rule.

The IOUs do not understand the need for a requirement that a minimum of 60 days be provided between the issuance of the RFP and the due date for proposals in response to the RFP. This has not been an issue in past RFPs, an appropriate timeframe for responding to an RFP will vary with circumstances, and a shorter time period may be appropriate. The IOUs request that section (12) be deleted.

Order Adopting Changes (1/27/03)

The order adopting changes stated:

(12) A potential participant may file with the Commission objections to the RFP limited to specific allegations of violations of this rule within 10 days of the issuance of the RFP. The public utility may file a written response within 5 days. Within 30 days from the date of the objection, the Commission panel assigned shall determine whether the objection as stated would demonstrate that a rule violation has occurred, based on the written submission and oral argument by the objector and the public utility, without discovery or an evidentiary hearing. The RFP process will not be abated pending the resolution of such objections.

The Florida PSC explained the revised rule as follows (page 6):

Subsection (12) of the rule provides potential RFP participants with an opportunity to file specific objections to a utility's RFP with this Commission. Under the rule as proposed October 25, 2002, objections would have to be filed within ten days of the post-issuance meeting. At the rule hearing, the IOUs expressed concern that this subsection could cause unnecessary delays to the need determination process, and may kill some projects. In particular, the IOUs were concerned that participants would want a "full-blown hearing" on their objections. To eliminate this concern, this subsection has been changed to set a specific time for filing objections, for the utility's response, and for our ruling on the

> objections. In addition, the changes limit objections to specific allegations of violations of the rule. This change should keep the focus on the appropriateness of the RFP terms, and not the application of the RFP to the individual participants, which was another concern raised by the IOUs.
>
> The changes approved herein require a participant to file objections within 10 days of the issuance of the RFP. Language has been deleted which would have required an objector to have attended the utility's post-issuance meeting, and which would have required waiver of untimely-filed objections. Language has been added which provides the utility with the option of filing a response within 5 days of an objection being filed. Within 30 days from the date of the objection, the Commission panel assigned shall determine whether the objection as stated would demonstrate that a rule violation has occurred. A change has also been added to make it clear that the Commission's ruling will be made without discovery or an evidentiary hearing, although oral argument is contemplated. We believe these changes will ensure that the objection process does not cause unnecessary delays to the RFP process. These changes should also provide greater clarity and certainty early on in the RFP process, and should help streamline and reduce the number of similar objections in the need determination process.

The steps that should actually be taken must take into account limitations on the resources of the utilities implementing the process, and the time required to take the step. For example, obtaining Commission approval of an RFP before it is issued might minimize later issues regarding the RFP, but such a requirement could add substantially to the time required to conduct an RFP process (particularly if the approval was made in a 'contested case" proceeding). Thus, prior approval is not recommended.

<u>Dispute Resolution</u>

Given the overall design of the RFP process in the Proposed Framework, the need for formal Commission involvement to resolve disputes should be limited. The parameters for the RFP will be worked out in the IRP process. Disputes about the utility's needs and the resources to meet those needs will be considered and resolved by the Commission when it approves the IRP Plan. Proposed Framework, ¶I.B.1.

Giving interested parties and the Commission the opportunity to review and comment on the RFP and the utility the opportunity to incorporate such comments in the RFP should minimize the chance for disputes that cannot be resolved among the utility, the independent observer (when the utility or an affiliate have submitted bids) and potential bidders.

Direct Commission involvement as a referee in the operations of the competitive bidding process will encourage bidders and others to frequently contact the Commission to favor their own cause and may jeopardize the fairness and objectivity of the competitive bidding process. For example, if the Commission staff provides information to one bidder but not to another the integrity of the process can be compromised. The Proposed Framework's approach for conducting informational meetings with the Commission and the Consumer Advocate would keep each apprised of issues that arise between or among the parties without placing the Commission in a direct day-to-day role in the process. Other processes where commissions had a direct active role proved to be an invitation for bidders to contact the commissions to vent their concerns and attempt to achieve a more favorable result. HECO response to PUC-IR-33.

The dispute resolution procedure should be established so that a bidder could not stop the RFP process and force some kind of formal resolution of complaints. Tr. (12/15) at 824 (Williams).

The HECO Companies believe that establishing competitive bidding guidelines early in the process is preferable to dispute resolution after the fact. It is more effective to take the time up-front to effectively develop the guidelines and procedures, which provide a clearer understanding of the process by all participants and a level of certainty at the outset to both the bidder and the utility. An attempt to resolve issues that breed disputes after the fact can lead to a contentious process every time the utility issues a solicitation, significantly driving up project costs (contrary to one of the primary objectives that competitive bidding is aimed to achieve) to the detriment of ratepayers. But of likely greater harm than increased costs is the potential for drawn out disputes to negatively impact the reliability of the isolated electric utility systems in Hawaii through delay in the final selection and ultimate implementation of needed firm capacity resources. HECO response to PUC-IR-45.

In the experience of the Company's consultant, Wayne Oliver, a framework that enables everyone to know the rules of the game prior to competitive bidding will result in fewer disputes. For example, Mr. Oliver was involved as an Independent Evaluator in the BC Hydro RFP process where no rules were established. The RFP was more or less developed "on the fly." Through that process, almost 20 addenda were issued to bidders. It was very confusing, and, ultimately, there were a number of disputes that came out of that process. Tr. (12/15) at 804-05 (Oliver).

2. Assume that the Commission should issue an order determining whether the utility has complied with the competitive procurement procedures. When should such an order be issued? Consider:

> *a. in the proceeding to approve the PPA, pursuant to the terms of the PPA, HRS § 269-27.2, HAR ch. 6-74, and HAR § 6-60-6(2), to the extent applicable?*
> *b. in a general rate case, pursuant to HRS § 269-16?*
> *c. in an energy cost adjustment clause case, pursuant to HAR § 6-60-6(2) and HRS § 269-16(b)?*
> *d. in a proceeding separate from each of the preceding three options?*

Response

The Proposed Framework provides that the Commission will review and approve the contracts that result from competitive bidding processes conducted pursuant to the Framework. The Commission may establish review processes that are appropriate to the specific circumstances of each solicitation, including the time constraints that apply to each commercial transaction. Proposed Framework, ¶II.B.4.

If the electric utility's self-build or turnkey project is identified as superior to bid proposals, the utility would seek Commission approval in keeping with established capital project application review procedures. Proposed Framework, ¶II.B.5. Within these two approval processes, the Commission could make a finding that the utility had complied with competitive procurement procedures.

III.D. Utility Cost Recovery of Wholesale Purchase Costs and Utility Self-Build Costs

1. Does Commission approval of a PPA preclude the Commission from making later disallowances due to --
a. imprudent negotiation of the PPA
b. imprudent management of the PPA
c. failure to enforce certain rights under the PPA?

Response

Responding to Commission Outline III.D.1.a, it is the Company's position that, in general, having approved the PPA, the Commission should not make later disallowances due to "imprudent negotiation of the PPA." Under the Proposed Framework, the Commission, in a separate proceeding, will have the opportunity to review and approve, or not approve, the PPA negotiated by the utility and the bidder selected by the utility. If the Commission has misgivings about the negotiations that resulted in the final PPA, the Commission should not approve, or should require modifications to, the PPA at that point. Once the Commission approves the PPA and the utility begins making payments to the IPP under the approved contract, the Commission should not disallow recovery of contractual payments made by the utility to the IPP due to "imprudent negotiation of the PPA in reliance on the Commission's earlier approval.

With respect to Commission Outline III.D.1.b and c, in general, the Commission may review the utility's management of the PPA, including its enforcement, or lack of enforcement, of provisions in the contract, and make disallowances where it has been demonstrated that the utility's management of the contract has not been prudent. However, before such determinations can be made, it should be demonstrated by the evidence that, based on the information available to the utility at the time of its management's action (or inaction), there was "imprudent management of the PPA" or "failure to enforce certain rights under the PPA" was imprudent.

Mr. Oliver is not aware of any cases on the mainland where a negotiated PPA was found to be imprudent. Tr. (12/14) at 723; 738-39. (Oliver).

<u>Discussion</u>

The Commission has addressed cost recovery for expenses incurred pursuant to an approved power purchase agreement in a substantial number of proceedings. For example, in approving HECO's amended PPA with AES Barber's Point, Inc. ("AES-BP", nka AES Hawaii Inc.), the Commission found that:

> 3. HECO may pass on to ratepayers the fuel component of the energy charge under the AES-BP contract, as amended, through HECO's fuel adjustment clause. Subject to paragraph 4 of this order, HECO may include in its rates in future rate cases the non-fuel portion of the energy charge and the capacity charge it is required to pay to AES-BP under the power purchase agreement.
>
> 4. The Commission reserves the right to review in HECO's future rate cases the prudency of HECO entering into the AES-BP contract and the reasonableness of the contract terms, including the reasonableness of the energy and capacity charges HECO is required to pay under the contract upon a showing that (a) HECO procured the Commission's approval in this docket through fraud or deception or through conscious or deliberate misrepresentation of facts or manipulation of data; or (b) HECO failed to disclose at the time of the Commission's decision in this docket, facts known to HECO or of which HECO should reasonably have known which bear upon the prudency of HECO's decision to enter into the AES-BP contract or on the reasonableness of the terms and conditions of the contract.
>
> 5. The Commission, further, reserves the right (a) to monitor and review HECO's administration and implementation of the AES-BP contract, including the exercise of options available to HECO within or without the contract; (b) to ensure HECO takes such

actions as are prudent and in the public interest which may become appropriate or necessary as a result of performance under the AES-BP contract; (c) to review and determine how the cost consequences of the failure of AES-BP to perform under the contract will be shared by HECO and the ratepayers; and (d) to consider what adjustments should be made in the event capacity in excess of that required by HECO develops in the future.

Docket No. 6177, Decision and Order No. 10448 (December 29, 1989), at 42-43.

The Commission made similar rulings in other decisions approving PPAs:

1. HECO's amended PPA with Kalaeloa Partners, L.P. ("Kalaeloa"), under which Kalaeloa currently provides 208MW of firm capacity from a dual-train combined cycle ("DTCC") facility burning low sulfur residual fuel oil ("LSFO"). Docket No. 6378, Decision and Order No. 10824 (October 31, 1990)(at 27-28), modifying Decision and Order No. 10369 (October 16, 1989).

2. HECO's amended PPA with AES Hawaii, Inc. ("AES-Hawaii") (originally known as AES Barber's Point, Inc.), which provides 180MW from a coal-fired facility. Docket No. 6177, Decision and Order No. 10448 (December 29, 1989) (42-43), modifying Decision and Order No. 10296 (July 28, 1989).

3. HELCO's amended PPA with Hamakua Energy Partners, L.P. ("HEP") (originally known as Encogen Hawaii, L.P.), which provides 60MW from a naphtha-fired DTCC facility.

4. MECO's amended PPA with A&B-Hawaii, Inc., through its Hawaiian Commercial & Sugar Company division ("HC&S"), which provides 12MW of firm capacity (and 4MW available through an under-frequency relay arrangement) from the generating units supplying power to its sugar milling operations. The HC&S generating units generally burn sugar cane waste (i.e., bagasse) and coal. MECO originally entered into the arrangement with Alexander & Baldwin, Inc. dba Hawaiian Commercial & Sugar Company ("HC&S"), under a PPA entered into in 1980.

There is federal and state case law (in other jurisdictions, since the issue has not been litigated in Hawaii courts) supporting the right of the utilities to continue to recover their power purchase payments made pursuant to the pre-approved PPA's. For example, the United States Court of Appeals for the Third Circuit ruled in Freehold Cogeneration Associates. L. P. v. Board of Regulatory Commissioners, 44 F.3d 1178, 1194 (3d. Cir. 1995):

> Finally, we hold that once the [regulatory commission] approved the power purchase agreement between [the QF] and [electric utility] on the ground that the rates were consistent with avoided cost, any action or order by the [regulatory commission] to reconsider its approval or deny the passage of those rates to [the electric utility's] consumers under purported slate authority was preempted by federal law.

2. Recovery of utility parallel planning costs

a. Who should pay for the utility's parallel planning costs? Consider.

(1) utility ratepayers

(2) all bidders

(3) winning bidders

(4) some combination of the foregoing

b. By what mechanism should cost recovery occur?

Response

Regarding Commission Outline III.D.2, the costs that an electric utility incurs in taking reasonable and prudent steps to implement Parallel Plans and/or Contingency Plans[31] should be recoverable through a utility's rates as part of the cost of providing reliable service to customers. Proposed Framework, paragraph VI.B. Thus, the utility's ratepayers will pay for the parallel planning costs through rates.

The capital costs that are part of an electric utility's Parallel Plans and/or Contingency Plans should be accounted for similar to costs for planning other capital projects. Such costs would be accumulated as construction work in progress ("CWIP"), and carrying costs would

[31] For a detailed discussion of the role of Parallel Plans and Contingency Plans, please refer to the Company's response to Commission Outline II.A.2 and II.A.3.

accrue on such costs. If the Parallel Plans and/or Contingency Plans are implemented resulting in the addition of planned resources to the utility system, then the costs incurred and accrued carrying charges would be capitalized as part of the installed resources (i.e., recorded to plant-in-service) and added to rate base. The costs would be depreciated over the life of the resource addition. Proposed Framework, paragraph VI.C.1.

If implementation of the Parallel Plans and/or Contingency Plans is terminated before the resources identified in such plans are placed in service, the costs incurred and accrued carrying charges included in CWIP would be transferred to a miscellaneous deferred debit account and the balance would be amortized to expense over five years (or a reasonable period determined by the Commission), beginning when the base plan resource is placed in service. The amortization expense would be included in revenue requirements when there is a rate case. Under appropriate circumstances, the Commission may allow additional carrying costs to accrue on the unamortized miscellaneous deferred balance. Proposed Framework, paragraph VI.C.2.[32]

3. Competitive effects of different cost recovery treatments

a. Where the utility selects its self-build option in a competitive bidding scenario: Should the Commission require the utility to absorb the risk that its actual cost will exceed the price associated with its self-build option?

b. Assume the answer is yes. What are the mechanics, in terms of bid submission and later ratemaking, necessary to achieve this result?

c. Should there be any exceptions to this rule?

Response/Framework

[32] With respect to any cost incurred by a utility, if it is a prudent utility activity, there needs to be an effective cost recovery mechanism. It has to be a given that a utility can recover prudently incurred costs. Parallel planning costs are no exception. Generally, the Commission has determined that parallel planning costs are the responsibility of the ratepayers. Otherwise, the expense of parallel planning would be added to the cost of the project, and the IPP would have to recover that cost through the prices paid by the utility. It is just a different mechanism of recovery. Ultimately, it comes from ratepayers. Therefore, there needs to be a mechanism whereby ratepayers will pay for that cost, unless, because of the peculiar circumstances of a given project, there are unusually high parallel planning costs. In that case, the parallel planning costs should lower the IPP's profit on the project because one of the risks the IPP had to take in order to acquire that opportunity was the responsibility for the parallel planning cost. Tr. (12/14) at 740-742 (Williams).

Under the Proposed Framework, the regulatory treatment of utility-owned or self-build facilities will be cost-based, consistent with traditional cost-of-service ratemaking, wherein prudently incurred capital costs are included in rate base. Any utility-owned project selected pursuant to the RFP process will remain subject to prudence review in a subsequent rate proceeding with respect to the utility's obligation to prudently implement, construct and/or manage the project consistent with the objective of providing reliable service at the lowest reasonable cost. Framework, Section VI.D.

With respect to Commission Outline III.D.3.b and c, the Stipulating Parties' approach (including the "mechanics") is as set forth in the Proposed Framework, paragraph VI.D. In that way, the regulatory treatment of the self-build facilities will be cost-based, consistent with the traditional cost-of-service ratemaking. Prudently incurred capital costs are included in rate base. The self-build project will remain subject to a prudence review in a subsequent rate proceeding with respect to the utility's obligation to prudently implement, construct and/or manage the project consistent with the objective of providing reliable service at the lowest reasonable cost.

The Proposed Framework addresses the comparative effects of different cost recovery treatments by requiring that all differences between utility self-build and/or utility owned facilities be evaluated, and that the evaluation, in effect, be "validated" by the independent observer.

If proposed utility self-build facilities or other utility-owned facilities (e.g., turnkey facilities), or facilities owned by an affiliate of the host utility, are to be compared against IPP proposals obtained through an RFP process, the electric utility should retain an independent observer to monitor the utility's conduct of its RFP process, advise the utility if there are any fairness issues, and report to the Commission at various steps of the process. Proposed

Framework, Paragraph III.H.7. As stated in this paragraph of the Framework, the utility could provide the independent observer with the utility's evaluation of the unique risks and advantages associated with utility self-build or other utility-owned facilities, including the regulatory treatment of construction cost variances (both underages and overages) and costs related to equipment performance, contract terms offered to or required of bidders that affect the allocation of risks, and other risks and advantages of utility self-build or other utility-owned projects to consumers. The independent observer may validate the criteria used to evaluate affiliate bids and self-build or other utility-owned facilities, and the evaluation of affiliate bids and self-build or other utility-owned facilities.

In order to do this, the utility (in conjunction with the independent observer) should propose methods for making fair comparisons (considering both costs and risks) between the utility-owned or self-build facilities and third-party facilities. As noted in the Framework, such a comparison between self-build or other utility-owned facilities and IPP facilities may include modeling likely variation in construction costs, plant efficiency, plant outages, and/or operation and maintenance costs and assigning a risk premium to the self-build or other utility-owned facilities, and the likely impact of IPP proposals on the utility's capital structure. Proposed Framework, Paragraph III.H.7.

Discussion

The Framework identifies steps that can be taken to provide bidders with reasonable assurance that their proposals will be "fairly" considered. The Framework indicates that those steps should not be implemented in a manner that creates an undue burden on the utility or its customers, who are the intended beneficiaries of the RFP process. The purpose of an RFP is to help the utility and its customers obtain new generation resources (See III.A.4.) that meet the objectives of the IRP "at the lowest reasonable cost", and to facilitate the acquisition of renewable energy resources (See III.A. 1.2.3.). The purpose is not to increase the amount of purchased power for the sake of competition, or to provide access to the Hawaii generation market on a "levelized playing field" basis. (See Transcript (12/14), pages 671-672.)

The utility is not simply a potential competitor in its own RFP process. The utility, along with its customers and its system, are intended beneficiaries of any RFP process that is pursued or mandated. It is the utility that has the obligation to serve. In Hawaii, the utility is not simply a provider of service, or the default provider of service, but is the provider of service.

In some of the mainland jurisdictions that pushed retail competition the strongest, utilities were encouraged or mandated to divest themselves of generation in the hope that the number of merchant generators would be increased, and customers would reap the benefits of an "ideal" competitive market. In California, utilities were not even allowed to acquire power through bilateral contracts. The results have been "less than optimal", particularly in the case of residential customers, and in some instances were catastrophic.

Based on the experience, and the uniqueness of the small, non-interconnected Hawaii markets, the Commission declined to implement retail competition in Hawaii. The Commission issued final Decision and Order No. 20584 ("D&O 20584") on October 21, 2003, which closed the competition docket instituted in 1996. The Commission determined that no action would be taken in the docket to implement retail electric competition or to substantially change the regulatory framework for the electric industry in Hawaii at this time. The Commission found that:

> Electric industry restructuring should only be initiated if it is in the public interest. Developments in other states indicate that, at best, implementation of retail access would be premature. In addition, projections of any potential benefits of restructuring Hawaii's electric industry are too speculative and it has

> not been sufficiently demonstrated that all consumers in Hawaii would continue to receive adequate, safe, reliable, and efficient energy services at fair and reasonable prices under a restructured market, at this time. Accordingly, the commission does not find it is in the public interest to completely restructure the electric industry at this time. We will continue, however, to keep a watchful eye on restructuring experiences in other states. In the alternative, the commission finds that it is in the public interest to work within the current regulatory scheme to strive to improve efficiency within the electric industry. (D&O 20584 at 14.)

The Commission also noted that:

> Hawaii is different from other states because, without interconnection to other states' energy transmission grid, Hawaii does not need to respond to the actions of its neighbors, and Hawaii does not have the advantages and disadvantages associated with being connected with other states. (D&O 20584 at 14 n.9.)

The Commission determined that it was in the public interest to work within the current regulatory system to strive to improve efficiency within the electric industry, and opened investigative dockets on competitive bidding and distributed generation to move toward a more competitive electric industry environment under cost-based regulation.

It is neither necessary nor reasonable to impose an arbitrary "cap" on the utility's recovery of its costs in order to facilitate a "fair" competitive bidding process. Before imposing such a cap, there would have to be a clear showing that such a departure from traditional cost-of-service rate-making is necessary, or that a focus only on cost risk makes sense, or that the unique Hawaii market, which does not include short-term market-based options, or power that can be imported from other jurisdictions), has been considered, or that unintended negative consequences have been considered.

In addition, the Company has a number of serious concerns about limiting the utility's cost recovery to its self-build bid. One of the fundamental issues in this proceeding is whether the Commission has the legal authority in the context of competitive procurement to hold a utility to its bid, that is, to prohibit in all future rate cases recovery of costs associated with the utility's self-build project exceeding the amount bid by the utility. The legality would be subject to challenge under H.R.S. §269-16, which provides that a utility is entitled to a fair return on utility property actually used or useful under the prudent investment standard. Tr. (12/14) at 751 (Williams).

The Commission has broad authority, although, in exercising that authority, a decision by the Commission will not be upheld if clearly erroneous in view of the reliable probative and substantive evidence or if the Commission acted in an arbitrary, capricious manner or if it abused its discretion. That determination would depend on the all of the facts and circumstances presented to the Commission. If the Commission held the utility to its bid but did not allow the utility to earn more than its actual cost, and if the Commission took that action to facilitate competition where an IPP would have been allowed to earn a return based on its bid price regardless of what its actual cost was, such an action by the Commission easily could be deemed to be arbitrary and capricious. Tr. (12/16) at 1121-22 (Williams).

If the Commission were to <u>require</u> a utility to submit a self-build proposal, it would be unreasonable and inconsistent with the regulatory compact[33] for the Commission to limit the way

[33] The Hawaii Commission has described the "long-standing regulatory compact" as follows:

> The regulatory compact has two aspects: (1) in return for a monopoly franchise, utilities accept the obligation to serve all comers; and (2) in return for agreeing to commit capital necessary to allow the utilities to meet the obligation, utilities are assured a fair opportunity to earn a reasonable return on the capital prudently committed to the business. In <u>Wash. Util. And Trans. Comm'n v. Puget Sound Power & Light Co.</u>, 62 P.U.R.45th 557, 581 (1984), the Washington Commission explained the regulatory compact in this fashion:
>
> "The social and economic compact of utility regulation begins with the premise that a regulated utility has an obligation to serve the public. [A] utility possesses an unending obligation to provide service to anyone

in which the utility could recover its cost. The Commission can configure an RFP process, but it cannot require IPPs to participate in that process. Tr. (12/14) at 752 (Williams).

Because the utility has the obligation to serve, it has the obligation to proceed with the project. It does not have the same protections in its "contract" that an IPP has. The utility does not have the ability to declare bankruptcy based on one project, by insisting that it only proceed with a project entity. There are just too many differences between the way the utility proceeds with a project and the way an IPP proceeds. The Company's position is that the Commission can take those differences into account in evaluating what is the best option for consumers, but to hold the utility to a particular specific bid is not in the public interest. Tr. (12/16) at 1127-28 (Williams).

In order to treat the utility in the same manner as an IPP, the utility should be allowed, in effect, to have a contract with itself, meaning that it would not be limited to a cost-of-service recovery, but could recover its purchase price with itself. Otherwise, the financial benefits for the utility would be limited on the upside, but it would absorb all the downside risk. By contrast, there would be no limit on an IPP's ability to realize a financial benefit on an identical project. As a practical matter, however, it is not realistic for a utility to have a contract with itself, because the Commission would still regulate all aspects of the utility, and even if the utility brought the project in at a lower cost, that financial gain could be taken away through other

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> within the service territory of that utility who demands service in accordance with approved tariffs.
>
> However, in order for the social duty to serve to be viable, the compact must also provide for a utility to recover expenses it prudently undertakes to meet the obligation. (Emphasis original.)"

Re Citizens Utilities Company, Kauai Electric Division, Docket Nos. 94-0097 & 94-0308, Decision and Order No. 14859 (August 7, 1996), at 13.

regulation of the utility's cost of service. Tr. (12/14) at 751-52 (Williams).

In order to put a utility's self-build project on an equal footing with an identical IPP project, the Commission would have to give up jurisdiction over that power plant. The only mechanism to control, even in a limited way, a power plant operated by an IPP is through a power purchase contract. There is no regulation by the Commission of an IPP's power plant. The Commission would have to assume the same position with respect to a utility's power plant if it were going to treat the utility like an IPP. Tr. (12/14) at 752 (Williams).

An IPP has another cost recovery advantage over a utility's self-build option; the IPP is guaranteed its cost recovery as soon as it begins delivering power because that would be specified in its contract. It does not have to wait for the Commission to approve the incorporation of that cost in rates unless that is provided in the PPA approved by the Commission. To put the utility on the same footing as the IPP, the utility would require that same guarantee in its contract with itself, namely that it would begin to recover its cost as soon as the facility went into commercial operation. Tr. (12/14) at 753 (Williams).

The key to a fair bidding process is to ensure that whatever risk is involved for ratepayers under the adopted cost recovery mechanism is taken into account in the evaluation process when comparing the utility's self-build proposal versus bids from IPPs. For example, a utility's self-build option might be evaluated by including a contingency for some cost overrun. rather than simply considering the estimated cost that the utility might project. Alternatively, a utility might choose to take on a risk of limiting the amount of its recovery, and it should be allowed to bid on that basis, but it would have to do so at the time it submitted its bid. Another possibility is that, if the utility is going to be able to adjust its in-service cost based on differences in financing cost, then bidders might be allowed to bid an option that allows them to adjust their capacity price based on changes in financing cost between the time they enter into the contract and the time that project enters into service (i.e., when they put into place long-term financing). Some of these alternatives can be taken into consideration in the options given to bidders. Some of these matters can be taken into consideration in how the utility's bid is evaluated. However, limiting the utility's right to recover its costs to the amount of its bid is neither appropriate nor reasonable.

Other Jurisdictions

The problems that may result from placing a limit on cost recovery for a utility's self-build proposal have been recognized in other jurisdictions. In a proceeding before the Louisiana Public Service Commission ("PSC") regarding market-based procurement, the Louisiana PSC noted that limiting cost recovery to the lesser of actual cost or the utility's cost estimate might encourage the utility to inflate its cost estimate, causing a low cost project to lose, and that the imposition of a cost cap for retail rate recovery might discourage utility projects that should go forward: "Moreover, as some commenters (e.g., Dynegy) have noted, the utility on certain occasions may have significant cost advantages over IPPs due to its ability to repower existing units and/or utilize existing, developed sites. This cost advantage should flow through to ratepayers as part of cost-based rates, but it might not do so if the utility is required to "bid" its self-build projects."

In response to arguments by some parties in the proceeding that the utility must "bid" its project into the RFP and limit cost recovery to its bid (or accept a cost cap), the Louisiana PSC stated, "This suggestion would eliminate the perceived bias (as well as shielding customers from the risk of cost overruns), but it also effectively would deregulate all new generation, which is not the purpose of this docket." Docket No. R-26172 Sub Docket A, Louisiana Public Service

Commission, ex parte. *In re: Development of Market-Based Mechanisms to Evaluate Proposals to Construct or Acquire Generating, Capacity to Meeting Native Load.* Supplements the September 20, 1983 General Order. (Amends and Supercedes the 4/10/02 General Order), February 16, 2004, at p. 4.

At the same time, the Louisiana PSC also noted that:

> [T]he Rule does not eliminate prudence reviews in subsequent rate and/or fuel proceedings with respect to the utility's obligation to prudently implement, construct and/or manage capacity projects or purchase power contracts, although the Phase I process is expected to reduce the need for such reviews. In the case of resources acquired subject to an exemption or exception, the utility retains the obligation to demonstrate prudence. If a utility capacity project or purchase power contract is approved under the Phase I process, the utility retains the obligation to prudently manage that resource (including construction cost control) during its entire life.

General Order issued February 16, 2004, in Docket No. R-26172A, at 6.

It appears that Utah also relies on its commission's ability to conduct post-installation prudence reviews. Utah enacted statutory provisions in 2005 dealing with competitive bidding. Rather than legislating a strict limit on cost recovery, one of the provisions permits commission review in a rate proceeding of increased costs for an energy resource, "[A]n increase from the projected costs specified in the commission's order issued under Section 54-17-302 (approving a significant energy resource decision) shall be subject to review by the commission as part of a rate hearing . . . ." Utah Code Ann. §54-17-303(1)(b). In addition, a utility may go to the commission and ask for an order to proceed if there is a change in circumstances or projected costs; if the commission orders the utility to proceed, then the commission shall allow in a rate case projected costs up to amount specified in order to proceed. Utah Code Ann. §54-17-304(3).

Regulatory commissions also rely on the use of an independent observer to ensure a fair comparison between utility and non-utility proposals.

The Louisiana PSC uses the term Independent Monitor (or "IM"). In a General Order issued February 16, 2004, in Docket No. R-26172A, (page 13), the LPSC identified the role of the IM as follows:.

> The IM will review and track the utility's conduct of the RFP to ascertain that no undue preference is given to affiliates and their bids, self build or self supply projects. This will include, to the extent necessary, reviewing the draft RFP and the utility evaluation of bids, monitoring communications (and communications protocols) with market participants; monitoring adherence to codes of conduct; and monitoring contract negotiations.

The language included in the proposed Framework for Hawaii was modeled based on language proposed in an on-going competitive bidding rules proceeding in Oregon. (The Public Utility Commission of Oregon (Ore. PUC), in Order No. 91-1383, directed each electric utility "to obtain at least a portion of its new power resources through the competitive bidding process." On October 4, 2002, the Oregon PUC opened an investigation to consider regulatory policy pertaining to new generating resources, Docket UM 1066. By Order No. 02-872, entered December 12, 2002, the PUC directed its staff is to organize workshops to cover the ratemaking treatment of new generating resources and the use of competitive bidding to acquire new resources. An Investigation Regarding Competitive Bidding, Docket UM 1182, was initiated on December 3, 2004. On September 26, 2005, the Oregon PUC Staff distributed a Straw Proposal, which was developed with significant input from parties to the proceeding, to update the Commission's rules adopted in 1991.)

The Oregon PUC Staff's Opening Comments filed September 30, 2005[34] included recommendations that:

> (1) "[T]he Commission allow electric utilities to use a self-build option in an RFP to provide a cost-based alternative for customers. Staff also recommends that utilities be allowed to consider ownership transfers within an RFP. However, if the utility chooses to consider these ownership options in an RFP, then the Commission should require the utility to use of an Independent Evaluator."

[34] Page 4.

(2) "[T]he utility and the Independent Evaluator evaluate the unique risks and advantages of any utility self-build or ownership options, including the regulatory treatment of construction costs, equipment failures and outages, and the costs of replacement capacity, energy, and ancillary services.'

Staff's proposed language to accomplish this was as follows[35]:

> i. The utility conducts the RFP process, scores the bids, selects the initial and final short-lists,-and undertakes negotiations with bidders.
> ii. The IE validates the utility's Benchmark Score and may validate, sample, or independently score all bids, at the discretion of the IE and the Commission. In addition, the IE evaluates the unique risks and advantages associated with the Benchmark Resource, including the regulatory treatment of construction cost overruns, equipment failures and outages, costs of replacement capacity, energy and ancillary services, and other risks and advantages of the Benchmark Resource to consumers.
> iii. Once the competing bids and Benchmark Resource have been scored and evaluated by the utility and the IE, the two should compare results. The utility and IE should work to reconcile and resolve any scoring differences.

Portland General Electric, in its Reply Comments dated October 21, 2005, proposed the following revisions:

> PGE proposes a more balanced characterization of the "unique risks and advantages" of Benchmark Resources described in Section 13(b)(ii) of Staffs Straw Proposal. As currently written, this Section characterizes "unique risks and advantages" as "including the regulatory treatment of construction cost overruns, equipment failures and outages, costs of replacement capacity, energy and ancillary services, and other risks and advantages . . ." This makes it appear that Benchmark Resources are generally riskier than other resources. However, Benchmark Resources also have a number of advantages that should be considered at the same time. These include the ability to upgrade or expand, possible construction cost savings, and the ability to extend the lives of these resources.
>
> Accordingly, we propose that Section 13(b)(ii) read as follows:
>
> The IE validates the utility's Benchmark Score and may validate, sample, or independently score all bids, at the discretion of the IE and the

[35] Staff Straw Proposal (Sept. 26, 2005), Section 13(b)(ii), at 4.

> Commission. In addition, the IE evaluates the unique risks and advantages associated with the Benchmark Resource, including the regulatory treatment of construction cost variances (both underages and overages), costs related to equipment performance, and other risks and advantages of the Benchmark Resource to consumers.

Mr. Oliver observed that most jurisdictions do not impose a cap on recovery, but allow a cost-of-service type bid. If the actual cost exceeds the bid price, there must be some justification of why the price was higher than estimated, with the recognition that if the utility underestimates by "50 percent to win the bid", there is going to be a prudence issue. If there is a justification for why those costs went up, then that would be part of the final determination of the cost. If there is some reasonable explanation to justify the increased costs, then that would be part of the prudence case, and the actual costs should be included in the utility's cost of service. Tr. (12/14) at 755-57 (Oliver).

At least one state has imposed a form of cost recovery cap. In Decision 04-12-048, issued December 16, 2004 in Rulemaking 04-04-003, the California Public Utilities Commission ("CPUC") adopted, with modifications, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company's (SDG&E) Long-Term Procurement Plans (LTPP) and provided direction to the utilities on the procurement of the resources identified in the LTPPs. (D.04-12-048 at 1.) The CPUC ruled that "IOUs will not be allowed to recover initial capital costs in excess of their final bid price for utility-owned resources, but any cost savings will be shared 50/50 between ratepayers and shareholders." (D.04-12-048 at 127.) The CPUC elaborated as follows:

> Bids from Utility-owned generation (IOU-build, turnkey, and buyouts) will be capped at initial capital costs.
>
> o If actual costs come in under the capped bid, then there should be a 50/50 sharing of savings between ratepayers and utilities.
>
> o Utility-owned resources that are selected in a solicitation will be eligible for Cost-

of-Service ratemaking (future plant additions, annual O&M expenses etc.).

D.04-12-048 at 140-141.

In D.05-09-022, the CPUC granted limited rehearing of D.04-12-048 on the sharing of cost cap savings, and stated that this issue will be part of the scope of the 2006 LTPP. D.05-12-022 at 8-9. In Decision 05-12-022 (December 15, 2005), the CPUC denied petitions to modify this part of D.04-12-048, but noted that: "We imposed the cost cap on only the capital cost because as expressed in PG&E's response to the Motion, it is the most significant portion of the total cost and the most accurately estimated cost component." D.05-12-022 at 11-12.

As noted above, circumstances in Hawaii do not warrant imposition of a cap. It is neither necessary nor appropriate to impose an arbitrary "cap" on the utility's recovery of its construction costs. Before imposing such a cap, there would have to be a clear showing that such a departure from traditional cost-of-service rate-making is necessary, or that a focus only on construction cost risk makes sense, or that the unique Hawaii market, which does not include short-term market-based options, or power that can be imported from other jurisdictions), has been considered, or that unintended negative consequences have been considered.

IV.A. Debt Equivalency Treatment of Long-Term PPAs

1. When is debt equivalency triggered?

a. To what extent does debt equivalency depend on contract terms? Consider:

(1) contract shifts operating risks to the IPP

(2) contract shifts fuel risks to the IPP

(3) contract gives utility right to own project on default

(4) other terms

b. To what extent does debt equivalency depend on --

(1) the size of a specific contract?

(2) the utility's total PPA obligations?

(3) the length of the contact?

<u>Response</u>

Responding to Commission Outline IV.A.1., the Company understands that the term "debt equivalency" refers to determinations by credit rating agencies that certain obligations of the Company that are not currently reported as liabilities on the Company's balance sheet should be reflected as debt in the ratios used to evaluate the Company's risk profile. In order to capture the risks associated with these obligations, the credit rating agencies calculate "imputed debt." CA-HECO-IR-19. As discussed further below, imputed debt is calculated by multiplying a "risk factor" by the present value of the fixed contract payments.

The credit rating agencies have determined that certain obligations that are not currently reported as liabilities for financial reporting purposes should be reflected as debt in the ratios used to evaluate a company's risk profile. In order to capture the debt-like features of PPAs, the credit rating agencies calculate "imputed debt." "Imputed debt" negatively impacts financial ratios. A company can offset the negative impact of imputed debt by increasing its equity and decreasing its other debt. Response to HREA-HECO-FIR-4. (In addition, as discussed below, changes in accounting standards may result in more actual debt being shown on HECO's financial statements as a result of either: (1) capital lease treatment or (2) consolidation of an IPP which is more highly leveraged than HECO. In order to offset the negative impact of the additional actual debt, the utility may have to increase its equity and decrease its other debt.)

With respect to Commission Outline IV.A.1.a., as discussed further below, these contract terms (i.e., "contract shifts operating risks to the IPP, contract shifts fuel risks to the IPP, and contract gives utility the right to own project on default) could all impact the "risk factor" that is assigned to the purchase power agreement(s). (This risk factor is multiplied by the present value of the fixed contract payments to calculate the amount of imputed debt.) It should be noted that when S&P raised the risk factor for HECO's existing purchase power agreements from 15% to

30%, the reason cited by S&P was the lack of a statutory guarantee of cost recovery for PPA payments.

With respect to Commission Outline IV.A.1.b., as discussed further below, debt equivalency depends upon all of those items listed (i.e., "size of a specific contract", the "utility's total PPA obligation", and "length of the contract"). The amount of imputed debt is calculated based in part on the present value of fixed contract payments. Accordingly, the "size of a specific contract" (which the Company understands to mean the size of the proposed project and the amount of the payments the utility has to make to the IPP), the "utility's total PPA obligation" (which the Company understands to mean the amount of the utility's payments to the IPP), and "length of the contract" are all factors that would go in to calculating the present value of the fixed contract payment. In addition, these factors could also be considered in determining the risk factor to be applied to the present value of the fixed contract payments.

Proposed Framework

The Proposed Framework provides that all relevant incremental costs to the electric utility and its ratepayers should be considered, including for example, the reasonably foreseeable balance sheet and related financial impacts of competing proposals. Proposed Framework ¶III.E.6. In addition, the Proposed Framework provides that the impact of purchased power costs on the utilities' financial ratios and/or balance sheets, and the potential for resulting utility credit downgrades (and higher borrowing costs), may be accounted for in the bid evaluation. Where the utility would have to restructure its balance sheet and increase the percentage of more costly equity financing in order to offset the impacts of purchasing power on its balance sheet, this rebalancing cost also should be taken into account in evaluating the total cost of a proposal for a new generating unit if IPP owned, and it may be a requirement that bidders provide all information necessary to complete these evaluations. Proposed Framework ¶III.E.8.

Discussion

Basically, rating agencies treat the fixed payments associated with power purchase agreements as debt in calculating the financial ratios used in the evaluation of the utility since the utility has incurred an obligation to make a stream of fixed payments to the seller over the life of the contract. Imputing or including the cost of purchased power as debt has the potential of adversely affecting a utility's capital structure and its interest coverage ratios due to this increased risk. A corresponding increase in the equity of the utility may be required to rebalance the capital structure and this cost needs to be accounted for in evaluating power purchase agreements. Because the cost of equity exceeds the cost of debt, this rebalancing of the utility's capital structure to accommodate the additional financial leverage of purchased power contracts imposes additional costs that must be considered in any economic evaluation of alternatives. As a result, while purchased power commitments do not involve direct capital investment, they do have financial implications that must be considered to allow for a meaningful comparison between supply alternatives. HECO SOP, Exhibit A at 24.

While recent accounting rules have affirmed how such costs should be treated, it is important to note that the HECO Companies have already been required by the credit rating agencies to rebalance their capital structures as a result of their purchased power commitments. The HECO Companies have had to add higher cost equity capital to balance the imputed debt attributed to existing non-utility power purchase agreements. HECO SOP, Exhibit A at 24.

HECO has been impacted as a result of entering into purchase power contracts. For example, in the early 1990's, HECO's credit rating was downgraded, in part as a result of the risks associated with the purchase power contracts it signed in the late 1980's. Also in the early 1990's, S&P developed its methodology for taking the risks of purchase power into consideration in evaluating a company's credit. As a result, HECO increased its equity ratio in order to improve its key financial ratios. Thus, the HECO Companies have been required to rebalance their capital structures as a result of their purchased power commitments, by adding higher cost equity capital to balance the "imputed debt" attributed to existing non-utility power purchase agreements.[36] HECO FSOP, Exhibit III at 3.

Financial ratio evaluations included in HECO's rate case test year 2005 incorporated imputed debt of $247 million at the beginning of 2005 and $239 million at the end of 2005 for a test year average of $243 million. The amount of rebalancing to try to maintain target financial ratios varies from period to period and over time. However, as of December 31, 2004, if HECO had no purchase power obligations, approximately $100 million less in equity would have resulted in the same equity ratio as the ratio it had with the imputed debt (45%). Since equity investors require a higher return than debt holders, the increased amount of equity increases the cost of electricity to ratepayers. HECO FSOP, Exhibit III at 3-4.

The financial impacts on the utility's balance sheet associated with increased purchased power costs generally are more of a financial risk to HECO than to most mainland utilities since most mainland utilities have a lower reliance on long-term purchased power arrangements. The power purchase contracts between HECO and independent generators are long-term in nature

[36] As indicated in the SOP, the credit rating agencies have determined that certain obligations of the Company that are not currently reported as liabilities on the Company's balance sheet should be reflected as debt in the ratios used to evaluate the Company's financial profile. In order to capture the risks associated with these obligations, the credit rating agencies calculate "imputed debt." Basically, rating agencies treat the fixed payments associated with power purchase agreements as debt on the utility's balance sheet since the utility has incurred an obligation to make a stream of fixed payments to the seller over the life of the contract. Imputing or including the cost of purchased power as debt has the potential of adversely affecting a utility's capital structure and its interest coverage ratios due to this increased risk. A corresponding increase in the equity of the utility may be required to rebalance the capital structure and this cost needs to be accounted for in evaluating power purchase agreements. Because the cost of equity exceeds the cost of debt, this rebalancing of the utility's capital structure to accommodate the additional financial leverage of purchased power contracts imposes additional costs. HECO FSOP, Exhibit III at 3-4 n.2.

and are exclusive with HECO, leading to long-term risk to the buyer. In fact, HECO is one utility that has already been required by rating agencies to rebalance its balance sheet by adding more equity to offset inferred debt from long-term purchased power agreements. HECO FSOP, Exhibit III at 4.

The HECO Companies are aware of two areas which one of the major credit rating agencies, Standard & Poors, currently imputes debt for HECO: (1) fixed payments associated with PPAs and (2) expected payments under operating leases. The Company's understanding is that S&P will evaluate payments associated with PPAs to assess the debt-like nature of the payments. For example, a PPA with a provision that requires the utility to take the output would be considered more debt-like than one that allowed the utility to determine what output it will take. Further, if payments are expected, even if they are not fixed, they may be deemed debt-like, and may result in imputed debt (similar to the way operating leases are evaluated by the credit rating agencies). Response to HREA-HECO-FIR-4.

The utility is rated by two credit rating agencies, Standard & Poor's ("S&P") and Moody's. Moody's is not as transparent as S&P with respect to how it imputes debt. Moody's has indicated it does impute debt related to purchase power agreements, but it is not as specific as to its methodology. S&P has been much more transparent in disclosing its methodology. It is generally the S&P approach to debt imputation that drives the Company's need to rebalance its debt and equity. Tr. (12/15) at 920-21 (Ohashi).

Standard & Poor's takes the present value of the total fixed payments over the life of the contracts, using a 10% discount rate for the present value calculation. It then determines a risk factor to apply to the contract to reflect the riskiness to the utility based on the terms of the contract and assurances of cost recovery. S&P refined its approach to assigning risk factors and increased the risk factor that it uses for HECO's contracts from 15% to 30%, based on the existing contracts being in base rates and the ECAC.[37] The risk factor is applied to the present value of the fixed payments under the contract to calculate the imputed debt:

Risk Factor x Present Value of Fixed Contract Payments = Imputed Debt

In addition, S&P imputes interest expense at 10% of the imputed debt balance. Response to CA-HECO-IR-19; HECO T-21 (von Gnechten) at 27, Docket No. 04-0113; Tr. (12/15) at 847-48 (Ohashi).

The Standard & Poor's article "'Buy Versus Build': Debt Aspects of Purchased-Power Agreements" provides a general description of Standard & Poor's approach to developing a risk factor. CA-HECO-IR-19, pp. 3-7. (This article has also been provided in Docket No. 04-0113 as Exhibit HECO-2111.) The article reviews the factors that Standard & Poor's takes into account, including some of the aspects of PPAs and how they effect debt imputation:

> While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

[37] In 2003 and 2004, Standard & Poor's issued updated guidelines industry-wide, and as applied to HECO, resulted in an increase of the risk factor from 15 to 30 percent. That increase was applied to existing contracts which formerly had been treated at 15 percent. S&P took a more critical view of the risks associated with purchase power contracts generally, and one of the factors cited was that, absent statutory recovery of purchase power payments by the utility, S&P was not comfortable assigning credit risk ratings as low as 15 percent. In other words, S&P was looking for a statutory requirement enabling a utility to recover purchase power payments to keep a risk factor of 15 percent, and in HECO's case, there is no such statutory requirement. Tr. (12/15) at 847-48 (Ohashi).

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery—and thus release from the payment obligation—is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor of TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

* * *

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors (sic) greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery.... Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant.... For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost

> recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used.... [I]t is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.
>
> * * *
>
> Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments.

CA-HECO-IR-19, at 3-5.

Regarding the possible relationship between contract terms and debt equivalency raised in Commission Outline IV.A.1, Company witness Gayle Ohashi noted during the panel hearing that when Standard & Poor's assigns a risk factor to purchase power contracts, the assurance of PPA payment recovery is not the only consideration. S&P reviews the terms of the contract and the risks assumed by the utility and the risk assumed by the independent power producer. Tr. (12/15) at 852-53 (Ohashi). However, when S&P raised HECO's risk factor from 15% to 30%, the reason cited by S&P was the lack of a statutory guarantee of cost recovery for PPA payments. Tr. (12/15) at 853-54 (Ohashi).

It is apparent from the excerpt from the S&P article quoted above, that its primary concern regarding PPAs is the risk posed by the fixed payment obligation, "[T]he overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer.... This article reiterates Standard & Poor's views on purchased power as a fixed obligation.... When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk." CA-HECO-IR-19, at 3. As noted above, a PPA that requires the utility to take the output would be considered more debt-like than one that allows the utility to determine what output it will take. When payments are expected, even if they are not fixed, they may be deemed debt-like, and may result in imputed debt. Response to HREA-HECO-FIR-4. The term of the contract and the magnitude of the fixed payment obligation under the contract may have an impact on the amount of debt imputed because those terms affect the discounted present value of the fixed obligation stream. Tr. (12/15) at 922.

In addition to the situation where credit rating agencies have imputed debt due to PPAs, there are two other situations where the utility, due to entering into a PPA, may have to take mitigating action to reduce its own debt and infuse equity to rebalance its capital structure.

First, certain accounting rules[38] may result in a PPA, although a contract, being considered as a capital lease resulting in 100% the net present value of lease payments being treated as debt. Tr. (12/15) at 879 (Oliver). In 2003, the United States Emerging Issues Task Force (EITF) reached a consensus on EITF Issue 01-8 whereby "arrangements or contracts that traditionally have not been viewed as leases may contain features that would require them to be accounted for as leases under Financial Accounting Standard 13, Accounting for Leases". Examples of arrangements that may fall under these rules include power purchase agreements. Under these rules, if the purchased power agreement meets the tests included in EITF 01-8 for lease accounting and the tests for a capital lease included in FAS 13 the transaction is explicitly recorded as a debt obligation on the utility's balance sheet. The accounting for capital lease obligations is not a discretionary issue and as noted the HECO Companies have had to abide by these rules. HECO SOP, Exhibit A at 24.

EITF 01-8 specifies tests to be applied to an arrangement (i.e., the PPA) to determine whether or not the arrangement contains a lease and specifies the circumstances under which an arrangement should be evaluated to determine whether or not it contains a lease. If the PPA is determined to be a lease, the lease must further be evaluated under FAS 13 to determine whether

[38] Capital lease treatment under Emerging Issues Task Force Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease" ("EITF 01-8") and Financial Accounting Standards Board Statement No. 13, "Accounting for Leases" ("FAS 13").

the lease is a capital lease or an operating lease. If the PPA is a capital lease, the payments must be evaluated to determine whether they meet the minimum lease payment criteria. If the payments are determined to meet the criteria for minimum lease payments, the purchaser would report the present value of the minimum lease payments as an investment in asset, related depreciation, a capital lease obligation and related interest expense. A capital lease obligation is a form of debt. To offset the increase in debt resulting from a capital lease, the utility may need to reduce its other debt and infuse equity to rebalance its capital structure. If the payments are not considered minimum lease payments, there is no lease asset and no lease obligation to record for financial reporting purposes; however there may be imputed debt implications. Similarly, if the lease is determined to be an operating lease, there is no lease asset and no lease obligation; however, there may be imputed debt implications. Response to HREA-HECO-FIR-4.

Second, under another accounting rule,[39] it may be necessary for a utility to consolidate the financial statements of an IPP with the utility's own financial statements, and that could have drastic consequences for the utility. Tr. (12/15) at 863 (Ohashi). Under FIN 46R, entities meeting certain specific criteria are deemed "variable interest entities" ("VIE"). If an entity is determined to be a VIE, a determination must be made as to whether there is a "primary beneficiary". The "primary beneficiary" is the enterprise that will absorb a majority of the entity's expected losses, receive a majority of the entity's expected residual returns, or both. The primary beneficiary must consolidate the VIE. FIN 46R could potentially require that the purchaser (the utility) under a power purchase agreement, consolidate the seller (the IPP). If the utility must consolidate the IPP in its financial statements, investors' assessments of the utility's risks as a result of the PPA may change. Consolidation of an IPP may have a negative impact on

[39] Financial Accounting Standards Board Interpretation No. 46 (revised December 2003) ("FIN 46R").

how the investment community views the utility's risk profile. If there is a negative impact, the utility may have to take mitigating action to reduce its own debt and infuse equity to rebalance its capital structure. Response to HREA-HECO-FIR-4.

The subjects of capital leases and the consolidation of the financial statements of an IPP with the utility's own financial statements are discussed in Exhibit C to HECO's SOP[40] and HECO's response to HREA-HECO-IR-8 (as replaced to include page 5 on May 5, 2005).

Other Jurisdictions

Several states have approved the inclusion of direct or imputed debt associated with purchased power commitments in the evaluation of resource options. For example, Florida utilities have included an equity adjustment in their RFP process. Also, the Florida Public Service Commission has acknowledged that an equity adjustment is appropriate to address the capital structure impacts associated with purchase power arrangements and it is reasonable to consider the financial impacts of purchased power. The Florida Commission determined that purchased power contracts imply higher debt leverage, and that the costs of rebalancing the capital structure to accommodate this debt should be considered in determining payments for purchased power. See e.g., Docket No. 040206-EI, Order No. PSC-04-0609-FOF-E1 issued June 18, 2004. Other states such as Wisconsin, Utah, California, and Oregon have recently raised the issue for consideration of resource options. The Wisconsin Public Service Commission concluded that the utility must be compensated for the adverse impact on its capitalization associated with capital lease obligations arising from purchased power transactions. HECO FSOP, Exhibit III at 4-5.

The California Public Utilities Commission stated in Decision 04-12-048 (Order

[40] This exhibit is identical to Exhibit C to the Application in Docket No. 04-0320, filed November 5, 2004, requesting approval of Amendment Nos. 5 and 6 to the Power Purchase Agreement between HECO and Kalaeloa Partners, L.P.

Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning, December 16, 2004):

> Debt Equivalence is a real cost that needs to be considered when evaluating bids from a PPA vs. a utility-owned resource. As SDG&E states, "[I]t is essentially undisputed that the credit analysts treat the utilities' long-term non-debt obligations, such as PPAs, as if they are in fact debt when they assess a utility's debt capacity." Consequently, the IOUs should take into account the impact of Debt Equivalence when evaluating individual bids in an all-source and RPS RFO, regardless of whether it is a fossil, renewable, or an existing QF resource. (Page 144)

Based on the HECO Companies' already significant purchased power obligations and the requirement already imposed on the company to rebalance its balance sheet as a result of these obligations, imputed debt and direct debt issues must be addressed in the development of the RFP process and an equity adjustment should be included in the evaluation of bids received, which warrant such treatment, along with the inclusion of transmission-related costs and operations-related costs for each bid. HECO SOP, Exhibit A at 25.

2. Comparability between PPA and self-build

> *a. What are the specific differences between the debt equivalency effects of a PPA and the utility's self-build option, given that the utility finances its self-build option with debt in part?*
>
> *b. When comparing a proposed PPA with the utility's self-build option, how should the utility take into account the similarities and differences between the capital structure effects of each?*

<u>Response</u>

Commission Outline IV.A.2.a and b correctly notes that either a utility self-build project or a PPA may result in the utility realizing additional debt. In the case of the self-build option, all the debt associated with the self-build option is on the books of the utility. Tr. (12/15) at 851 (Ohashi). In the case of a PPA, determinations by rating agencies may require the utility to increase the amount of debt recognized on the utility's balance sheet. The significant point for present purposes is that the additional debt from either source might require a utility to rebalance its debt and equity in order to avoid an adverse revision of its credit rating. Because equity investors expect a higher rate of return than debt investors, increasing the amount of equity will increase the utility's costs.

The focus should not be on the differences between debt on the books from a utility self-build project versus imputed debt from a PPA, but rather on the fact that both forms of debt result in cost to the utility, and, in evaluating a utility self-build proposal and proposed PPAs, the utility should be able to take into account the full impact of the cost resulting from each proposal. That approach is consistent with the Proposed Framework which provides that all costs that would be incurred by the utility and its customers should be taken into account in the bid evaluation and selection process. Proposed Framework, ¶III.A.1.

Standard & Poor's believes that its adjusting of a utility's financial statements based on its evaluation of PPAs "allow[s] for more meaningful comparisons with utilities that build generation." CA-HECO-IR-19, at 3. In order for a utility to make a meaningful comparison of a self-build proposal and PPA, the total cost of each must be considered, including the cost of debt that results from each proposal.

3. What technical methods should the Commission require for translating applying debt equivalency analysis to specific IPP offers and utility self-build options? Consider:

- *a. Commission-specified percentage debt figures (e.g., 10%)*
- *b. Commission-specified sliding scale with pre-defined minimum and maximum figures*
- *c. utility internal analysis followed by Commission review*

<u>Response</u>

Responding to Commission Outline IV.A.3., the Company favors option c., utility internal analysis followed by Commission review. Option IV.A.3.a is too rigid as the determination is not based on the specific terms of the contracts and the specific circumstances facing the utility (e.g., amount of purchased power on the system, length of the contract, whether there is a statutory guarantee for the cost recovery of PPA payments).

Option IV.A.3.c is preferred over Option IV.A.3.b, as it does not prescribe any parameters that could constrain the results of the analysis (i.e., pre-defined minimum and maximum figures), and would be based on the specific circumstances facing the utility (e.g., terms and conditions of the contract, amount of purchased power on the system, regulatory environment concerning the cost recovery of PPA payments). In addition, under the preferred option, the Commission still has the opportunity to review the result.

Other Jurisdictions

One technique for dealing with imputed debt in comparing an IPP proposal with a self-build option was considered in a proceeding before the Florida Public Utilities Commission concerning proposed amendments to rules for competitive bidding. In that proceeding, Florida's investor-owned utilities proposed a method for making an "apples-to-apples" comparison of PPAs and self-build options. Rather than include a specific evaluation method in the amended competitive bidding rule, the Florida Commission required that all RFPs must include "a detailed description of the criteria and the methodology, including any weighting and ranking factors," thus providing flexibility to the utilities to develop proposed methodologies for dealing with imputed debt in evaluating proposed PPAs. In re: Proposed revisions to Rule 25-22.082, F.A.C., Selection of Generating Capacity, Florida Public Service Commission, DOCKET NO. 020398-EQ, Comments of Investor Owned Utilities, p. 14 (November 15, 2002.)

4. In HECO's pending case, the company and the CA differed by about $20 million on the return on equity issue, but ultimately settled this issue. Hypothetically speaking, under what circumstances would a PPA's cost-of-equity effect be sufficiently small to "get lost in the noise"?

Response

The decision to settle a contested issue in a rate case is different from deciding whether a regulatory framework should permit consideration of all material information by a utility when implementing the objectives of the framework. As in any contested proceeding, a party's willingness to compromise on one issue is based on the overall settlement of issues and should not be viewed in isolation. Thus, the settlement of the return on equity issue in the HECO rate case does not indicate that it was unimportant or that it became "lost in the noise".

Competitive bidding should enable the comparison of a wide range of supply side options, including power purchase arrangements, utility self-build options and turnkey arrangements (i.e., build and transfer options). Proposed Framework, ¶I.B.2. In order to ensure that the generation acquired is at the lowest reasonable cost, utilities must be able to take into account all utility cost impacts that the addition of the new generation will have on the utility. For example, if utilities will have to restructure their balance sheets and increase their percentage of more costly equity financing in order to offset the impacts of purchasing power on their balance sheets, then this rebalancing cost must also be taken into account in evaluating the total cost of the new generating unit. To exclude such costs could result in a selection of a proposal that was not the lowest reasonable cost proposal.

IV.B. Other Considerations

1. What requirements should the Commission establish concerning evaluation of each of the following considerations?

a. Reliability considerations

(1) Credit rating: Should the Commission establish credit rating cutoffs, whereby IPPs or developers with lower ratings are precluded from bidding at all?

(2) Track record

(a) Should the Commission establish experience prerequisites, whereby developers with insufficient experience are precluded from bidding at all?

(b) If the utility creates a new affiliate for purposes of bidding, will the new affiliate have zero experience for purposes of applying an experience screen?

(3) Development feasibility

(a) siting status

(b) ability to finance

(c) environmental permitting status

(d) commercial operation date certainty

(e) engineering design

(f) fuel supply status

(g) bidder experience

(h) reliability of the technology

(4) Operational viability

(a) operation and maintenance plan

(b) financial strength

(c) environmental compliance

(d) environmental impact

(5) Effects of total amounts of firm and as-available purchase power on utility's system

b. Operational flexibility

(1) dispatchability

(2) flexibility of maintenance schedules

(3) ramp rates

(4) quick start capability

(5) coordination of planned maintenance

c. Contract flexibility

(1) in-service date flexibility

(2) expansion capability

(3) contract term

(4) stability of the price proposal

d. Cost considerations

(1) Pricing path

(2) Post-contract benefits

(3) Willingness and ability of seller to accept financial risk

e. Other public interest considerations

(1) net impact on the number of jobs created or lost

(2) net impact on the state's economy (increase or decrease in state gross product)

(3) net impact to the ratepayer (increase or decrease in rates and net bills)

(4) level of fossil emissions introduced or avoided to our atmosphere

(5) increase or reduction in the amount of imported fossil energy

(6) reduction in the exposure to fuel price volatility and supply

<u>Response</u>

In general, the factors cited by the Commission should be considered, along with other factors, in evaluating bids. However, the Commission generally should not establish requirements in the Framework, either with respect to pre-requisites for bidding or evaluation criteria used in selecting projects through the RFP process.

The Proposed Framework addresses a number of factors that should be taken into consideration when evaluating bidders and their proposals. Most, if not all, of the considerations are encompassed within the factors set forth in the parties' Proposed Framework.

With respect to pre-requisites for bidding, the Framework provides that a pre-qualification process may be incorporated in the design of some bidding processes, depending on the specific circumstances of the utility and its resource needs. Proposed Framework, paragraph III.B.5.[41] In addition, as part of the design process, the utility should develop and specify the type and form of threshold criteria that will apply to bidders. Examples of potential threshold criteria include requirements that bidders have site control, maintain a specified credit rating, and demonstrate that their proposed technologies are mature. Proposed Framework, paragraph III.B.6.

The type and form of non-price threshold criteria should be identified in the RFP documentation. Such threshold criteria may include, among other criteria, the following:

a. project development feasibility criteria (e.g., siting status, ability to finance, environmental permitting status, commercial operation date certainty, engineering design, fuel supply status, bidder experience[42], and reliability of the technology) (Commission Outline IV.B.1.A.(3));

[41] Pre-qualifications are discussed further in the Company's response to Commission Outline II.B.2.

[42] A typical threshold might require that a bidder must have completed one project of the same type and size as the project it is proposing. Other utilities have used a different number, two projects or three projects of a similar technology or three projects in total. A track record criterion functions more as a self-screen for the bidder. For example, if a wind developer receives an RFP for a 500 megawatt combined cycle project, it may think twice about submitting a bid because it may get eliminated up front. Tr. (12/15/) at 968-69 (Oliver). For a discussion of pre-qualification requirements, see the Company's response to Commission Outline II.B.2.

b. project operational viability criteria (e.g., operation and maintenance plan, financial strength, environmental compliance, and environmental impact) (Commission Outline IV.B.1.a(4));

c. operating profile criteria (e.g., dispatching and scheduling, coordination of maintenance, operating profile such as ramp rates, and quick start capability) (Commission Outline IV.B.1.b); and

d. flexibility criteria (e.g., in-service date flexibility, expansion capability, contract term, contract buy-out options, fuel flexibility, and stability of the price proposal) (Commission Outline IV.B.1.c).

Proposed Framework, paragraph III.E.9.a through d.

With respect to the evaluation of bids, the RFP process should allow for bids received in response to an RFP to be compared to one another and to the utility self-build project (or the generic resource identified in the IRP Plan, if no self-build project proposal is being advanced). Proposed Framework, paragraph III.E.1.

The evaluation criteria and the respective weight or consideration given to each such criterion in the bid evaluation process may vary from one RFP to another (depending, for example, on the RFP scope and specific needs of the utility). Proposed Framework, paragraph III.E.2.

The design process should address credit requirements and security provisions, which may apply to (a) the qualification of bidders, and/or (b) bid evaluation processes. Proposed Framework, paragraph III.B.7.

The bid evaluation process may include consideration of differences between bidders with respect to proposed contract provisions, and differences in anticipated compliance with such provisions, including but not limited to provisions intended to ensure:

a. generating unit and electric system reliability;

b. appropriate risk allocations;

c. counter-party creditworthiness; and

d. bidder qualification.

Proposed Framework, paragraph III.E.3.a through d.

Proposals should be evaluated based on a consistent and reasonable set of economic and fuel price assumptions. Proposed Framework, paragraph III.E.4.

Both price and non-price evaluation criteria (e.g., externalities and societal impacts, and preferred attributes consistent with the approved IRP Plan, and items identified in Commission Outline subparagraph 1.e) may be considered in evaluating proposals. Proposed Framework, paragraph III.E.5. The weights for each non-price criterion may not be fully specified in advance of the submission of bids, as they may be based on an iterative process that takes into account the relative importance of each criterion given system needs and circumstances in the context of a particular RFP. Proposed Framework, paragraph III.E.10.

In evaluating competing proposals, all relevant incremental costs to the electric utility and its ratepayers should be considered (e.g., these may include transmission costs and system impacts, and the reasonably foreseeable balance sheet and related financial impacts of competing proposals). Proposed Framework, paragraph III.E.6.

The impact of purchased power costs on the utilities' balance sheets, and the potential for resulting utility credit downgrades (and higher borrowing costs), may be accounted for in the bid evaluation. Where the utility would have to restructure its balance sheet and increase the percentage of more costly equity financing in order to offset the impacts of purchasing power on its balance sheet, this rebalancing cost also should be taken into account in evaluating the total cost of a proposal for a new generating unit if IPP owned, and it may be a requirement that bidders provide all information necessary to complete these evaluations.[43] Proposed Framework, paragraph III.E.8.

With respect to Commission Outline paragraph IV.B.1.a(5), the amount of purchased power that a utility already has on its system, and the impacts that increasing the amount of purchased power may have, should be taken into account in the bid evaluation. Proposed Framework, paragraph III.E.7.

Discussion

The HECO Companies already are committed to purchase a high percentage of firm capacity and energy from independent power producers ("IPPs"). As the level of power purchased from IPPs increases, the PUC must increase reliance on the utility's ability to manage the IPP performance through the terms and conditions of its contracts.

The percentage of firm capacity provided by IPP's on HECO's system has increased from 0% prior to the RFP to approximately 26% since Amendment Nos. 5 and 6 to the Kalaeloa amended PPA became effective in September 2005. The percentage of HECO's baseloaded capacity provided by IPP's is even higher – about 35% assuming Kalaeloa provides 209 MW. FSOP, Exhibit 3 at 2-3.

[43] Imputed debt and other impacts on a utility's balance sheet resulting from entering into PPAs is discussed in the Company's response to Commission Outline IV.A.

	2004 IPP Capacity as a Percent of Firm Capacity	2004 IPP Generation as a Percent of Total Net-to-System Generation	2006 IPP Capacity as a Percent of Firm Capacity	2006 IPP Generation as a Percent of Total Net-to-System Generation
Oahu	25%	39%	26%	42%
Maui	6%	7%	6%	16%

HECO has been able to manage the integration of the Kalaeloa, AES and H-Power facilities into its system, but there is substantial uncertainty as to how much more firm power could be purchased without substantial negative impact on HECO's operational flexibility. Moreover, it is expected that there will be opportunities in the future to purchase additional renewables on a firm capacity basis (for example, if an additional waste-to-energy capacity is added at Campbell Industrial Park), and if the percentage of purchased power is increased, it should be accompanied with the benefit of adding renewables.

The presence of a PPA between the utility and an IPP, however, does not provide the utility with as much operating flexibility as the utility has with its own units. While the PPA can specify operating conditions favorable to the utility (such as coordination of maintenance, dispatchability, etc.), the utility generally has less control over plant maintenance practices, operational considerations, fuel conversion opportunities, and environmental enhancements. In contrast, the utility has such operating flexibility with its own units. Tr. (12/15) at 975 (Simmons); HECO FSOP at 3.

Utilities have the obligation to serve their customers while IPPs who supply capacity and energy to the utilities under PPAs may be obligated to provide to the utility only those items and services, or to perform only those duties, that are covered by provisions in the PPA. At times, this can constrain the utility's operating flexibility. As a result, a utility has much more flexibility to adjust to changed circumstances if it owns and operates it own units, than if it purchases power under long-term PPAs, because PPAs cannot be drafted to provide for all future contingencies and changed circumstances.

By the same token, the Commission can not exercise the same level of regulatory control over IPPs that it has over the utility. In particular, the PUC does not generally have access to the financial information of IPPs or control over their profitability to ensure that the utility system customers receive an adequate benefit for the power being purchased.

Over the years, utilities have developed contractual provisions for PPAs that attempt to address the operational constraints utilities face with IPPs. HECO's response to PUC-IR-8 addresses contractual mitigation in detail. But, as indicated in the HECO response, although these provisions can resolve some of the constraints, contracts cannot fully mitigate them.[44] Exhibit "A" to this Opening Brief discusses how IPPs can constrain a utility's operating flexibility and how utilities have attempted to use contractual provisions to address the operational constraints utilities face with IPPs.

2. Methods of evaluating nonprice and price factors

a. Should the Commission require one or more methods for applying price and nonprice criteria? Consider:

(1) Nonprice criteria are threshold requirements, followed by evaluation on price only

(2) Price only evaluation, w/ nonprice as a tie breaker

(3) Actual scoring of each nonprice factor, combined with scoring of price factors

b. If the Commission should not require one or more methods for applying price and nonprice criteria, who should develop these methods, and subject to what level of Commission review?

c. If turnkey proposals compete with non-turnkey proposals, how should the utility and the Commission value the additional benefits of the turnkey offering?

[44] HECO FSOP, Exhibit 1 at 5-6.

Response

Regarding Commission Outline IV.B.2., the Company has indicated that both price and non-price factors will be considered in the evaluation of bids. The Stipulating Parties' Proposed Framework sets forth the guidelines to be followed in evaluating bids. This subject is discussed in response to Commission Outline IV.B.1, above. As discussed in response to Commission Outline IV.B.1, both price and non-price criteria may be considered in evaluating proposals and the weights for each non-price criterion may not be fully specified in advance of the submission of bids, as they may be based on an iterative process that takes into account the relative importance of each criterion given system needs and circumstances in the context of a particular RFP. Proposed Framework, paragraph III.E.10.

The Proposed Framework provides guidelines on how the evaluation criteria discussed above in response to Commission Outline IV.B.1 should be used. The evaluation and selection process to be used should be identified in the RFP documentation, and may vary based on the scope of the RFP. In some RFP processes, a multi-stage evaluation process may be appropriate. Proposed Framework, paragraph III.F.1. Utilities may be expected to document the evaluation and selection process for each RFP process, for review by the Commission in approving the outcome of the process (i.e., in approving a PPA or a utility self-build proposal). Proposed Framework, paragraph III.F.2. A detailed system evaluation process, which uses models and methodologies that are consistent with those used in the utility's IRP processes, may be used to evaluate bids. In anticipation of such evaluation processes, the RFP should specify the data that would be required of bidders. Proposed Framework, paragraph III.F.3.

In the competitive bidding process, non-price criteria are generally balanced with price criteria to evaluate and select bids for a short-list or even final selection. There is a challenge to combine non-price points with a pricing relationship between proposals. The conversion of price scores to points is an issue that emerges in some bidding processes. As a result, many solicitations use the combination of price and non-price scores to select a short-list and then determine their portfolio based on price only. While selection of the winning bid or portfolio of resources is generally based on total net present value revenue requirements, some utilities will use least cost as an indicator of selection but will use non-price factors as a "tie breaker". For example, through the process identified above, at the end of the process it will be possible to compare different projects or portfolios relative to their non-price scores and total net present value revenue requirements. PUC-IR-32.

There are mechanisms to account for the non-monetary costs or benefits of different types of resources. The most obvious method is to account for non-monetary factors in the evaluation process. Most utilities have developed evaluation processes that include both monetary and non-monetary elements. HECO listed a number of non-monetary factors in the response to PUC-IR-32. These non-monetary factors can include score ranges based on project size, resource type, location, fuel type, stability of the price stream, etc. The importance of each non-monetary factor will be based on the views and needs of the individual utility or bidding guidelines. PUC-IR-62.

With respect to Commission Outline IV.B.2.c, the guidelines to be followed in evaluating bids included in the Stipulating Parties' Proposed Framework (as discussed in response to

Commission Outline IV.B.1) allows the evaluation process to take into consideration the value of the additional benefits of the turnkey offering. This refers to some of the criteria as an example of how the value would be taken into account by the guidelines.

DATED: Honolulu, Hawaii, June 6, 2006.

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This exhibit addresses the potential benefits and disadvantages of competitive bidding, as well as the operational constraints utilities face with IPPs and the ability of contract provisions to address the operational constraints utilities face with IPPs.

The potential benefits and disadvantages of competitive bidding were addressed in Exhibit 1 to HECO's FSOP, based primarily on the experience of HECO's consultant, Mr. Oliver, with competitive bidding on the mainland, and the application of that experience by Mr. Oliver and HECO to unique circumstances of Hawaii's electric utilities.

Potential Benefits of Competitive Bidding

The hoped for benefits of competitive bidding included the following:

(1) Bidding has encouraged increased competition in some areas.

The response of bidders to competitive bidding processes on the mainland has varied depending on the location, requirements of the soliciting utility, and cost to develop a project.

The response to a competitive bidding process in Hawaii will likely not achieve the same level of activity as on the mainland, due to the smaller capacity requirements in Hawaii, the lack of merchant plants seeking power contracts, lack of short-term options, and more limited market access. In addition, development costs are likely to be higher and economies of scale are not significant.

(2) Competitive bidding can promote an organized, structured process.

An important benefit of competitive bidding is that all bidders and proposals participate in an organized, structured process. If the utility's PURPA obligations are not superseded by the competitive bidding process, however, one of the major benefits of competitive bidding may not be realized.

(3) Bidding has often contributed to competitive prices and more choices.

One of the primary goals of competitive bidding is to solicit and evaluate a wide range of resource options so that the best deals (among a range of options) for customers are selected.

On the mainland, the overall experience with competitive bidding programs is that competition has led to a range of prices and products with the opportunity to select lower cost options, due to several factors, such as the recent "glut" in merchant power generation and the financial problems faced by a number of power generators. Also, IPPs may be more willing to accept provisions allocating more cost and operational risks to them if they are bidding against other potential project developers; they may seek "out" clauses if they are not able to pass the risks on to their contractors, or if their financing parties are unwilling to accept the risks.

(4) Bidding can encourage the development of new technologies and products.

Effectively developed competitive bidding processes can encourage a wide range of options, including new technologies, although natural gas-fired combined cycle options have been the dominant form of capacity contracted through competitive bidding processes.

(5) Competitive bidding allows the host utility to clarify unique system characteristics in the RFP.

For example, if the utility values dispatchability or other operating flexibility associated with a proposed unit, it could request that a bidder offer such an option and/or evaluate the impacts of dispatchability or operational flexibility in the bid evaluation process. Likewise, a well structured competitive bidding framework should allow the utility to value factors such as location, transmission access/cost of system upgrades, operational flexibility, financial impact, in-service date flexibility, and fuel supply access.

(6) A properly structured competitive bidding process can limit self-dealing.

In most RFP processes on the mainland, the host utility plays a major role in the competitive bidding process including: (1) designing the RFP documents, evaluation criteria, and power purchase agreement; (2) managing the RFP process, including communications with bidders; (3) evaluating the bids received; (4) selecting the bids based on the established criteria; (5) negotiating contracts with selected bidders; and (6) competing in the solicitation process with a self-build option, if feasible.

The "solution" to limiting self-dealing while encouraging utility participation has been to use an "independent observer" to monitor and report on the utility's conduct of its bidding process, evaluation of the bids, and selection of the winning bidder. This solution, however, can add to the cost of the process.

7. Competitive bidding can provide greater regulatory certainty.

Conceptually, the selection of resources through a market test should serve to facilitate the regulatory process and alleviate the possibility for extended proceedings and the uncertainty associated with cost recovery and regulatory approvals. A well-designed and implemented RFP process can minimize the risk of legal challenges to the results of the procurement process.

<u>Potential Disadvantages of Competitive Bidding</u>

While there are a number of advantages or benefits associated with competitive bidding there are also a number of potential disadvantages or major issues that must be recognized and addressed in developing a competitive bidding process that is workable in Hawaii, including:

(1) Implementation of competitive bidding can lead to increased reliability risk.

The isolated nature of the island's electrical system places a premium on reliability of power supply and increases the risk of project default and/or the failure of the independent generator to deliver the power. Unlike the mainland, Hawaii's electric utilities cannot resort to purchases of energy from the market during periods of generation shortfall if the project does not deliver the power as required under the contract.

In addition, increases in the penetration of non-utility resources could exacerbate reliability concerns if projects do not perform in accordance with their contracts during operations, or new technologies introduce unintended consequences.

IPPs do not have the same "obligation to serve" that the utility does, and their performance is not subject to regulatory review. IPPs generally will make decisions on whether or not to provide capacity or energy based on economics, and not on the potential impact of their decisions on the utility's customers. When customers experience a service interruption that is based on a shortfall of generation, the customers look to the utility, not the IPP, as the cause.

More stringent contract provisions such as higher security levels, clearly defined milestone schedules and associated damages if milestones are not adhered to, and other financial disincentives have been applied as solutions to mitigate this problem in other jurisdictions. On the mainland, access to security allows the utility to replace the contracted power through market purchases and the application of liquidated damages to make the utility's customers whole.

However, in Hawaii, even with stringent contract provisions and penalties for failure to perform under the contract, there is still the potential for an IPP to default on its obligation and incur the penalties. If the IPP cancels the project, the costs to customers could be much greater than the contract penalties alone if system reliability is jeopardized. At the end of the day, customers need electricity and contractual penalties paid by an IPP to the utility cannot replicate that.

In addition to more stringent contract provisions, parallel planning is another option to mitigate risk, particularly given the isolated nature of our island utility systems. Under this option, HECO could continue to proceed with a self-build option until it is highly certain that the awarded project will meet its commercial operation date. The costs for such parallel planning would be recovered by HECO, and would need to be considered as part of the overall cost to provide reliable power to customers.

Another possible option to potentially mitigate the reliability risk to customers is to allow HECO the option to buy the awarded bidders project if the bidder defaults on the contract.

(2) The development and implementation of an effective competitive bidding process can be very time consuming.

A three to four year time horizon from development of the competitive bidding procedures to development and issuance of the RFP, and to negotiation and approval of a contract with a selected bidder is not unusual. This limits the flexibility of the host utility to solicit for resources quickly if requirements change. The time required to undertake a competitive bidding process can be lengthy as well.

Because of the length of time needed to develop and implement a well-designed competitive bidding process, certain utility capacity addition projects already under development should not be subject to the competitive bidding process.

(3) The resource commitment and cost to the host utility and regulators to undertake a competitive bidding process can be very substantial.

For example, in undertaking a competitive bidding process, utilities generally establish several internal project teams for the price analysis, non-price analysis and contract negotiations. This usually requires several analysts to undertake the pricing assessment as well as representatives from a number of departments within the Company to undertake the non-price analysis (e.g. financial analysis, environmental analysis, fuels, engineering, transmission system analysis, operations, siting/land, and legal). If the utility is proposing a self-build option, available resources may be further limited to protect confidentiality or outside resources may be required. In any case, the cost and commitment of resources is significant.

Small utilities, such as HECO, may be particularly constrained in their ability to dedicate the appropriate amount of resources to adequately staff the project teams required. In other words, while the utilities employ personnel with the specialized skills and experience necessary to undertake the tasks described above, there are not enough of these people to divide into the specific functions needed to carry out bidding and evaluation responsibilities, while at the same time being excluded from carrying out their planning and evaluation responsibilities with respect to the utility's own projects. Such a resource problem has existed even for larger utilities.

The costs for an Independent Observer to observe or review the bidding process could be quite high as well. For example, it was reported in a recent bidding process on the mainland that the cost of the Independent Observer exceeded $500,000. HECO's competitive bidding consultant is aware of another competitive bidding process where the cost of the Independent Observer was approximately $1 million.

One of the lessons learned in undertaking a competitive bidding process for the first time is that the utility generally underestimates the resources, time required to undertake the RFP process, and the cost for undertaking the process, particularly the bid evaluation and contract negotiation phases.

The development and administration of competitive bidding processes will also place a significant burden on the Commission and its staff, and the Consumer Advocate and its staff, to monitor and review the process, in addition to reviewing and approving the outcome of the process.

(4) Implementation of a competitive bidding process can result in elimination of certain resources that may be favored from a public policy perspective.

A strict implementation of competitive bidding may result in the elimination of less economical but publicly desirable resources competing on an equal footing with more economic options. Renewable projects such as wind, photovoltaics, biomass and landfill gas, and even other fossil fuel technologies such as coal, have had difficulty competing against gas-fired combined cycle projects in an all supply source RFP. Bidding programs designed to enhance the benefits of one resource relative to another may be contrary to the intent of the competitive bidding process and may result in a conflict with other public policy goals.

(5) While mainland competitive bidding processes provide valuable models, one size does not fit all.

The needs of isolated utility systems in Hawaii, which are significantly different from the utility systems on the mainland, could influence the design and development of a competitive bidding process and the associated rules and guidelines. In many areas of the U.S. mainland, utility systems are part of a larger regional market, which provides utilities with access to a range of power supply options and products and reduces reliability risk. In these systems, failure of the supplier to deliver could result in the buyer being indemnified based on the financial penalties contained in the power purchase agreement. The financial nature of the contract provides the utility the opportunity to purchase replacement power at market prices. The seller has to compensate the utility the difference between the contract price and the market price. The utility is made financially whole and still has access to reliable power supplies in the broader market.

In an isolated power market such as Hawaii, the inability to procure other sources of power could be devastating. There is no "broader market" from which replacement power could be obtained. The utility needs physical power to meet customer reliability requirements.

Furthermore, purchased power already plays a significant role in the power market in Hawaii. The impact of additional purchased power on the reliability and operating flexibility of the power system in Hawaii needs to be addressed in the competitive bidding process used in Hawaii.

(6) Competitive Bidding and procurement of power resources through IPP power purchase agreements may reduce the utility's ability to manage the unique grid requirements of isolated utility systems.

Contractual arrangements for the purchase of power may sometimes constrain the flexibility to manage system issues that evolve over time. Modifications to generating units (or to PPAs themselves) needed to meet new operating requirements, such as cycling on and off or being operated at lower load levels, may be difficult to obtain. Project financing agreements may limit the ability of the IPP to agree to modifications, even if the utility compensates the IPP for making the modifications.

(7) Competitive bidding and procurement through independent power purchase agreements may reduce utility and regulatory control over utility system operations.

The Commission cannot exercise the same level of regulatory control over IPPs that it has over the utility. In particular, the Commission does not generally have access to the financial information of IPPs or control over their profitability to ensure that the utility system customers receive an adequate benefit for the power being purchased. As the level of power purchased from IPPs increases, the Commission must increase reliance on the utility's ability to manage the IPP performance through the terms and conditions of its contracts.

(8) Various forms of competition already exist that can achieve the goals of competitive bidding.

The utilities already use competitive bidding processes for equipment and service procurement to ensure cost management. In addition, IPPs already have the opportunity to propose projects that can deliver power at less than the costs of the utility's alternatives, as evidenced by the fact that there are already significant IPP levels of penetration on the HECO systems. Also, utility customers are continuously looking for ways to reduce costs. Competitive alternatives already exist from many kinds of self-generation (distributed) resource providers, including renewable technologies such as photovoltaics, fuel cells, and combined heat and power (CHP) facilities.

<u>Operational Constraints Utilities Face With IPPs</u>

Utilities have the obligation to serve their customers while IPPs who supply capacity and energy to the utilities under PPAs may be obligated to provide to the utility only those items and services, or to perform only those duties, that are covered by provisions in the PPA. At times, this can constrain the utility's operating flexibility. As a result, a utility has much more flexibility to adjust to changed circumstances if it owns and operates it own units, than if it purchases power under long-term PPAs, because PPAs cannot be drafted to provide for all future contingencies and changed circumstances.

(1) An IPP may be reluctant to increase its expenses in order to hasten a return from a planned maintenance outage to accommodate the utility's need for capacity at a particular time.

(2) An IPP that is capable of providing more capacity than it is obligated to under the terms of the PPA may limit the output of its facilities to the grid, even though the utility may have a need for the capacity at a particular time. The utility would need to rely on persuasion and cooperation arising from good business relationships in order to obtain anything beyond the terms of the PPA.

(3) IPPs are dispatched based on PPA pricing provisions, which often contain pricing curves. If it turns out that the pricing curves do not actually track the IPP's costs, then the IPPs will seek to be dispatched (and will exercise their rights under the PPA) so as to maximize their profitability (taking into account differences between their prices and costs), not to minimize the utility's costs.

(4) An IPP may refuse to operate during certain periods of the week because it is more economical to pay a penalty according to the PPA for being unavailable than to operate.

(5) An IPP may be experiencing frequent forced outages, which may result in service interruptions to utility customers. Yet the utility only has a limited amount of latitude under most PPAs to require evaluations of the IPPs power plant configuration, and to design and specify improvements to reduce the number of forced outages.

(6) Many IPP units are designed, built, owned and operated by mainland- or foreign-based corporations who may not fully understand the intricacies of operating small, isolated, non-interconnected island grids. Often they do not comprehend the relative impact of their generation on these smaller isolated grids, and may resist operating under system conditions such as low frequency, low voltage, high frequency or high voltage under which utility units have to operate under system contingency conditions. The result is a higher potential for grid instability.

(7) Additionally, IPPs do not have the same "obligation to serve" that the utility does, and their performance is not subject to regulatory review. IPPs generally will make decisions on whether or not to provide capacity or energy based on economics, and not on the potential impact of their decisions on the utility's customers. When customers experience a service interruption that is based on a shortfall of generation, the customers look to the utility, not the IPP, as the cause.

(8) Shifting the obligation to serve to IPPs would be difficult, if not impossible under current regulatory schemes. In general, absent regulatory restructuring, a utility would not be able to "assign" its obligation to serve and, thus, be relieved of this duty. The Commission may or may not be able to impose obligations on non-utilities as a condition for approving certain contracts, but the obligations would be contractual, and not a result of the non-utility's status. (PURPA and state law specifically exclude certain forms of utility-type regulation for QFs and non-fossil fuel producers. Also, the Commission has found that IPPs that sell solely to utilities are not utilities themselves.) As a practical matter, however, the imposition of utility obligations on power producers and/or broad requirements that such power producers indemnify utilities for their inability to fulfill their obligation to serve may render projects unfinanceable.

Other examples were discussed by the HECO Companies at the panel hearing. There was an instance where an IPP tripped off the line, and its power was needed to make the afternoon peak. HECO asked the IPP to do whatever it could to get back on line, but the IPP's manager was concerned about the high cost of starting its boilers at the same time. In other words, the IPP weighed the decision whether to incur additional expense against doing everything possible to get that unit back on line as soon as possible. Tr. (12/15) at 981-82 (Simmons).

Another example is that typically the utility will assume risk to keep the lights on, but the IPP will not or cannot in order to protect its investment. For example, typically, there will be a requirement by an IPP's lenders or insurers to have an underfrequency relay on the generating unit. By contrast, HECO does not have underfrequency relays on its generating units. Operating conventional technologies in an underfrequency mode runs the risk of damaging the turbines. The utility sees its obligation as trying to sustain the system as long as possible. It does not have an automatic level where it will trip all of its units just because of a dip in frequency due to a fault or some kind of disturbance on the system. The utility will try to keep its units on as long as it can, and leave it to its operators to determine when it is necessary to trip the units. However, an IPP will not risk the cumulative damage of operating in an underfrequency mode. When the frequency drops just a few hertz, an IPP will want to trip off the system. That is exactly what the utility does not want generating units to do during a frequency excursion because that would exacerbate the problem and potentially send the system into instability and could black out the whole island. In other words, the Company bears the risk of damage to its equipment by staying at the particular load level. The Company has tried to draft PPAs so that the IPP bears this risk, but has not had much success in getting IPPs to lower their under-frequency thresholds to the levels that the Company feels would be more appropriate. Tr. (12/15) at 976-78 (Simmons).

The Company also had an instance where one of the IPPs tripped off line because a lightning bolt struck its substation and damaged a lightning arrestor. On that day, HECO was short of generating capacity, and it was imperative that that IPP make the repairs and come back on line as soon as possible. If it has been HECO's equipment, it would have been easy for one of HECO's operating managers to make a determination to cut off the damaged lightning arrestor, which is there to protect the generating units or equipment against another potential lightning strike, for the short term to get the unit back on to meet the evening peak. Tr. (12/15) at 978-81 (Simmons).

The IPP acknowledged the need to come back on line to meet the evening load and HECO specifically asked it to cut off the arrestor and to come back on as soon as possible. The IPP ultimately decided to try to make that repair before coming on line because the manager would have been taking a significant risk by coming on line if there had been another lightning strike (i.e., the equipment and facility would have been damaged) and he would have had to answer to his owners. Tr. (12/15) at 978-81 (Simmons).

Ability of Contract Terms to Address the Operational Constraints Utilities Face With IPPs

Over the years, utilities have developed contractual provisions for PPAs that attempt to address the operational constraints utilities face with IPPs. HECO's response to PUC-IR-8 addresses contractual mitigation in detail. But, as indicated in the HECO response, although these provisions can resolve some of the constraints, contracts cannot fully mitigate them.[1]

By their very nature, there are limitations inherent in the use of PPAs:

(1) Although PPAs are written with care and are improved upon with every new PPA that is negotiated, every PPA is subject to interpretation. The IPP will interpret the contract to its advantage, which can lead to disputes, which can be costly to resolve.

(2) A utility has much more flexibility to adjust to changed circumstances if it owns and operates it own units, than if it purchases power under long-term PPAs. PPAs cannot be drafted to provide for all future contingencies and changed circumstances, especially when they cover contract periods in excess of twenty years.

(3) When building and operating its own unit, the utility can make changes in the operation of the unit and can modify the unit when appropriate, which cannot necessarily be done with purchased power under a PPA. For example, the utility generally will have more flexibility to accelerate or defer the in-service dates of its own units and to change the manner in which its own units are operated, and to adjust the maintenance schedules and the manning of its own units.

[1] HECO FSOP, Exhibit 1 at 5-6.

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(4) In the case of a change that requires the amendment of a PPA, the approval of the amendment generally will have to be negotiated with the IPP's owners (which may be a partnership or limited partnership), the IPP's lenders (which may be a group of lenders), and possibly even with certain suppliers under long-term contracts with the IPP; all of whom are represented by counsel.[2]

(5) The PPA's inherent lack of flexibility becomes magnified as the term of the contract is extended. This occurs because the assumptions used in negotiating the PPA become less precise as the period being forecasted increases. To the extent that these assumptions do not accurately predict future circumstances, any inflexibility inherently caused by the legal obligation of a long-term contract or by specific contract terms based on those set of assumptions would tend to be magnified.

(6) The ability of an IPP to respond to the utility's needs would be governed by the terms and conditions of the PPA. The only way to provide the PPA with flexibility to adjust to all potential changed circumstances would be to grant the utility the right to act unilaterally to serve its own interests, provided that the facility was not damaged by the utility's actions. To the extent that an IPP is unwilling to grant the utility such rights under a PPA, the utility's flexibility would be diminished.

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[2] These approvals are in addition to approval from the Commission, which may also apply to changes in utility facilities requiring capital expenditures.
An IPP's decision to reject a request to change its PPA would not be subject to Commission review. Thus, the success of negotiations to amend a PPA will depend on the terms of the PPA and the economic impact of the modifications on the individual interests of the entities with an interest in a PPA, not the benefit of the amendment to the utility's customers.

To gain a better perspective on the unique nature of the Hawaiian electric system relative to mainland systems, the major characteristics of each system are contrasted below.[1]

(1) Given the interconnected nature of utilities in many regions of the mainland, product and resource diversity is generally greater and a portfolio of resource options, contract terms, and product types is more likely. By contrast, it is expected that the number of options in Hawaii will be limited to new, long-term resource options. Resource and contract diversity options may also be more limited since options such as merchant generation, short-term contracts with marketers, and flexible products are not available in Hawaii. Suppliers will not build excess capacity and will insist on long-term contracts since there is no alternative market for the power. While suppliers on the mainland could offer a shorter-term contact and wheel the power to a broader market after the contract terminates, this option is not reasonable in Hawaii, with no alternative market. Suppliers have a limited outlet and, therefore, will seek longer term contracts. The utility will also need assurance of a long-term source of supply, especially given the long lead time needed for development or replacement resources.

(2) Given the size of the utility systems on each Island and the expected level of load growth, the amount of capacity required via a competitive bidding process is likely to be for a smaller amount of capacity than is traditionally required on the mainland, where it is not uncommon for utilities to request between 500 and 1,000 MW per solicitation. As a result, there may be fewer competitors to supply the power required, since most project developers prefer to construct larger units (as development costs are usually similar no matter the size of the project). Also, since economies of scale are common with larger projects, developers prefer to construct larger units and spread the development costs over more megawatts.

(3) Unlike mainland systems, there are no transmission interconnections between islands that allow for larger scale projects and broader market access. As a result, each island will have its unique needs and will place different values on resource options.

(4) HECO already relies on non-utility generation to meet a significant portion of its power supply requirements. This indicates that a viable non-utility market is already effectively present. Also, the financial impacts on the utility's balance sheet associated with increased purchased power costs will likely be more of a financial risk to HECO than most mainland utilities with a lower reliance on long-term purchased power arrangements. The percentage of firm capacity provided by IPP's on HECO's system is about 26% since Amendment Nos. 5 and 6 to the Kalaeloa amended PPA became effective in September 2005. The percentage of HECO's baseloaded capacity provided by IPP's is even higher – about 35% assuming Kalaeloa provides 209 MW. As the level of IPP penetration increases, there are also operational risks that are difficult to quantify, but also increase, because the utilities do not have direct control over the operation and maintenance of the IPP generating units.

(5) The power purchase contracts between HECO and independent generators are long-term in nature and are exclusive with HECO, leading to long-term risk to the buyer. In fact, HECO is

[1] HECO FSOP, Exhibit I at 12-14.

one utility that has already been required by rating agencies to rebalance its balance sheet by adding more equity to offset imputed debt from long-term purchased power agreements.

(6) System reliability and resource availability are very important in Hawaii given the isolated nature of the utility system in Hawaii. Contract provisions will need to reflect this requirement. The reliability of specific generation resources in interconnected systems may not be as important as in isolated systems. Power contracts have become more focused on financial arrangements with liquidated damages paid to the buyer in case of default designed to keep the buyer financially whole. As a result, if a seller defaults, the buyer merely collects the damages and buys the make-up power in the market. For utilities in Hawaii, contract provisions will be more stringent, and financial damages will not make the utility and its customers "whole" if generation shortfalls result.

(7) By the nature of the island energy system, fuel options are more limited in Hawaii than on the mainland. In particular, there are no natural gas sources, unlike on most mainland systems where natural gas-fired projects dominate. Also, on the mainland, many utilities are offering gas tolling options to power generators, thereby absorbing the fuel risk. This is possible since the utility may also have a portfolio of gas supply contracts and transportation arrangements.

(8) The unique operational characteristics associated with the electric system in Hawaii would have to be accounted for in any competitive bidding process. These include the unique considerations and operational aspects of an isolated utility system (i.e., plant size limitations, quick start capability, spinning reserves, quick-load pick-up capability, minimum load requirements, reliability requirements, cycling requirements, redundancy, frequency and voltage control, system frequency bias, and other factors), load growth uncertainty, land use restrictions, and permitting requirements.

(9) Economies of scale and scope are more important competitive factors in the mainland markets and the development schedule will likely be much shorter than in Hawaii.

(10) Due to the nature of the power system in Hawaii with no outside interconnections and available options, HECO may be required to undertake a parallel planning process in case a selected project fails.

(11) Capacity installation costs are higher in Hawaii. The costs of developing new generating resources in Hawaii that can meet the unique requirements to operate in a non-interconnected island grid are invariably underestimated by those relying upon cost estimates for similar resources to be installed on the mainland. Moreover, the costs tend to be site-specific. Only the developers with acquired sites would be able to submit realistic bids, and those who bid based on mainland-derived cost estimates (who might well be the low bidders) would not be able to finance or build their proposed projects.

Introduction

Competitive Bidding emerged as a means of procuring power supplies beginning in the mid 1980's. The main driver of competitive bidding was the need to institute some degree of order in the power procurement process as a result of the response to the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). PURPA required utilities to offer to purchase capacity and energy from qualifying facilities at the utility's avoided cost. While the original intent of PURPA was to encourage the development of small power producers, renewable resources, and small scale cogeneration facilities, developers were able to qualify larger power generation facilities based on the creation of steam hosts to justify the projects under the FERC efficiency standards. The result was a surplus of power supply for several utilities who were required to sign contracts for power from these facilities at the utility's projected avoided costs. For a number of utilities, the primary source of stranded cost exposure was the above market cost of these PURPA contracts. HECO SOP, Exhibit B at 1.

An important benefit of competitive bidding is that all bidders and proposals participate in an organized, structured process. This is generally accomplished through a bidding process that requires all bids to be submitted at the same time, with all bidders providing complete and consistent information, with all bids being evaluated based on the same set of economic and fuel price assumptions, and with all bidders playing by the same set of rules. The evaluation of unsolicited proposals, such as traditional PURPA projects, can be complicated by different timing for proposal submission, and incomplete or inconsistent proposals. If the utility's PURPA obligations are not superseded by the competitive bidding process, one of the major benefits of competitive bidding may not be realized. HECO FSOP, Exhibit I at 1.

Discussion

In the event it is determined that a competitive bidding process should be implemented, one subject that must be addressed is how will the competitive bidding process work in conjunction with the obligations of the utility under PURPA, the rules established by the Federal Energy Regulatory Commission ("FERC") under PURPA, and state rules (such as those in Title VI, Chapter 74 of the Hawaii Administrative Rules ["HAR"]) implemented pursuant to the FERC rules. HECO FSOP, Exhibit II at 36.

The Company's position is that for firm capacity resources, the way the competitive bidding process would work in conjunction with PURPA would be that when a utility identifies a capacity need, the utility could issue an RFP for a new resource. All supply-side options will be eligible to bid, including QFs. If the QF wins the bid, it will negotiate a contract with the utility for capacity and energy at the bid price, which effectively is the avoided cost. If a QF does not respond to the RFP, then it would not be entitled to a capacity payment as the project would not defer or displace any capacity. HECO FSOP, Exhibit II at 37.

The effect of this would be that for firm capacity resources, the competitive bidding process would take precedence over the requirement that a utility purchase capacity and energy at or below avoided costs from a QF under PURPA. In other states, the competitive bidding processes replaced the process for contracting with QFs from a cost-based approach to market-based approach and one designed to result in a greater level of benefits to customers, and were deemed consistent with FERC guidelines implementing PURPA. HECO FSOP, Exhibit II at 37.

For as-available resources, if there is an RFP, and the QF wins the bid, the QF will negotiate a contract with the utility for the energy at the bid price. For as-available resources, if there is not an RFP, the utility may still have to negotiate with developers on a project by project basis. HECO FSOP, Exhibit II at 37.

In order to effectuate that competitive bidding would take precedence over the requirement that a utility offer to purchase capacity and energy at or below "avoided costs" (determined based on a utility's base resource plan) from a QF under PURPA, the rules established by FERC under PURPA, and state rules implemented pursuant to the FERC rules, changes may have to be made to the state rules implemented pursuant to the FERC rules. Until such changes are made to the state rules, the utility might be subject to claims that the utility was obligated to negotiate for the purchase of capacity and/or energy at or below "avoided costs" from a QF outside the scope of an RFP. Of course, if the utility's needs for firm capacity are not through the RFP process, then the utility's "avoided capacity costs" for capacity offered outside the scope of the RFP would be deemed to be zero. HECO FSOP, Exhibit II at 37.

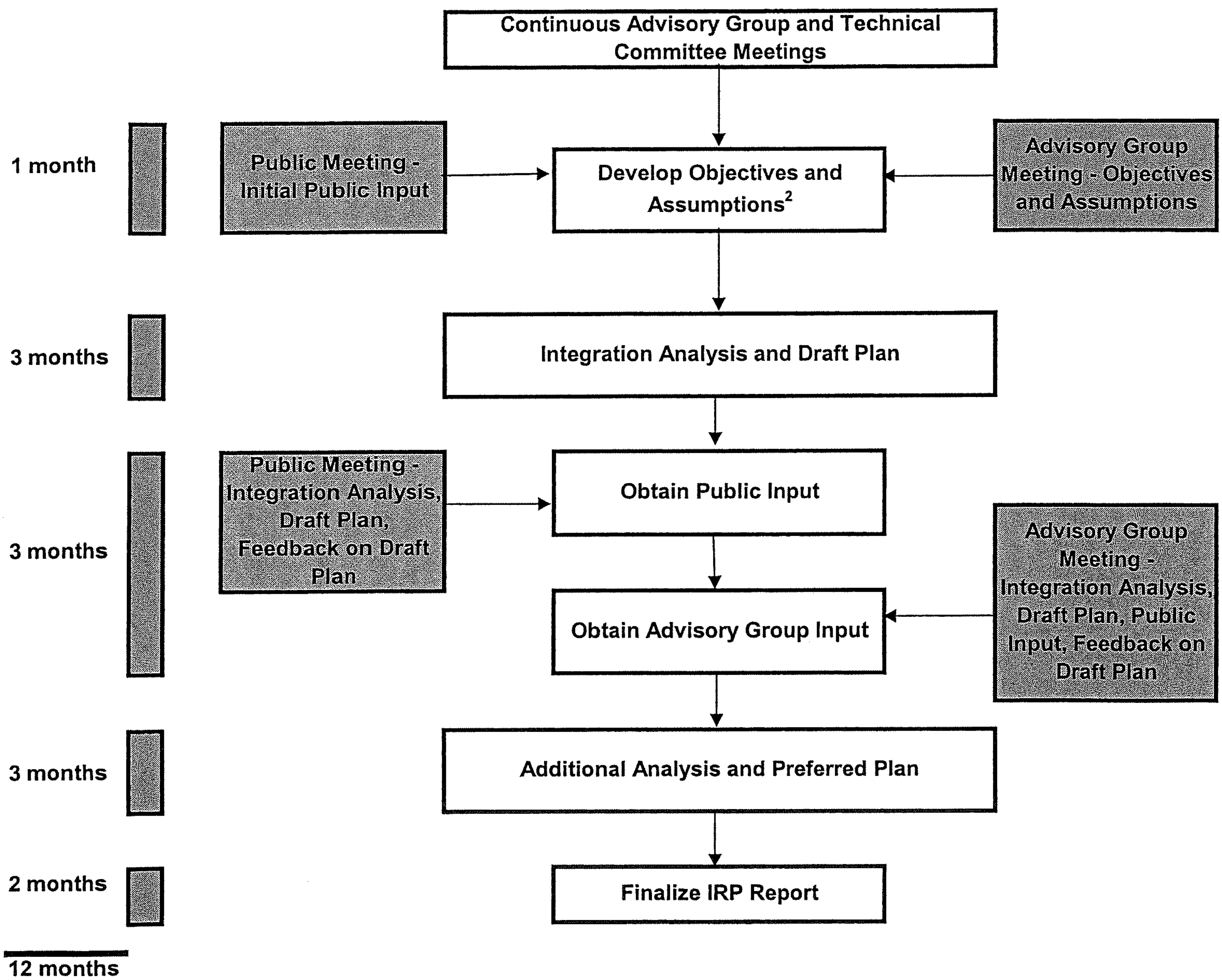
The current IRP process used for HECO's IRP-3 was a more dynamic, transparent and collaborative process with the public than in previous IRP processes. The process included an Advisory Group of key representatives from government agencies, the business community, environmental and cultural interest groups that helped guide the direction of the IRP planning process and provide input at a policy level. The process involved nine meetings of the Advisory Group and twenty-one meetings of associated Technical Committees. Discussions were held on the many complex issues of integrated resource planning, including the objectives development, sales and peak forecast development, DSM and Supply-Side resource options characterizations, capacity planning, plan development and integration and preferred plan selection.

Shortening the existing IRP process to increase the effectiveness of the competitive bidding process might be possible, but would require trade-offs. For discussion purposes, a possible one-year process to develop an IRP plan (from the start of IRP cycle through the filing of the IRP Plan and Report with the Commission) was developed by HECO. The one-year process is depicted in a flowchart provided to the parties (see Attachment 1 of March 3, 2006 letter to the Consumer Advocate), a copy of which is attached to this exhibit. A timeline comparison (a copy of which is attached to this exhibit) of the existing IRP plan development process (HECO IRP-3) to the possible one-year IRP plan development process illustrates the tradeoffs in planning activities that would result from shortening the existing IRP development process to a one-year timeframe. As shown on the comparison timeline, the existing IRP development process included public input on the objectives, resources, integration, finalist plans, draft preferred plan and draft IRP-3 Report through nine Advisory Group, twenty-one Technical Committee and two public information meetings. The one-year IRP development process timeline would involve significant reduction in opportunity for public input with only two Advisory Group meetings and two public information meetings during the IRP development process. In addition, the company would provide a draft preferred plan for public review and comment, however, the shortened timeframe would not allow public review of a draft IRP report prior to filing with the Commission.

To maintain public participation in the IRP process and to partly off-set the reduction in opportunity for public participation during the plan development phase, Advisory Group meetings could be held on a periodic basis before and after plan development. In addition, to accomplish the one-year IRP development process, stakeholders must be willing to work cooperatively to adhere to established timelines.

To realize the benefits of the shortened IRP plan development process and to further increase the effectiveness of a competitive bidding process, an expeditious review and decision on the company's IRP Plan will be necessary.

COMPETITIVE BIDDING DOCKET
Working Meetings with Parties (For Discussion Purposes Only)
HECO Proposed 1-Year IRP Plan Development Process Flowchart[1]



Notes:

1) Provided for discussion purposes only to Parties in the Competitive Bidding Docket No. 03-0372 to illustrate a potential schedule to develop and file an IRP in a one-year timeframe to accommodate the possible use of competitive bidding to acquire the resources or block of resources included in the IRP. A one-year IRP development process would result in significantly less public participation and transparency, which HECO deems to be very important. HECO is willing to discuss alternative approaches.
2) Initial Objectives to include quantitative targets for threshold objectives (e.g., reliability criteria and renewable portfolio standards) and description of non-threshold objectives. Non-threshold objectives to be quantified and presented with draft plan.

COMPETITIVE BIDDING DOCKET
Working Meetings with Parties (For Discussion Purposes Only)
HECO IRP-3 Versus Proposed 1-Year IRP Plan Development Timeline
(Public Meetings & Major Milestones)

HECO IRP-3

Subject	Date	Day No. (Approx.)	Duration of Major Tasks (Approx.)
Ad hoc group meeting - IRP Process Overview	Jul-03		
Ad hoc group meeting - Design of IRP Process	Aug-03		
PUC Order Opening Docket for IRP-3	Sep-03	0	
Begin Development of Objectives and Assumptions	Sep-03	1	Development of Objectives and Assumptions - 7.5 months
Advisory Group Meeting - Overview meeting 1	Sep-03	13	
Advisory Group Meeting - Overview meeting 2	Oct-03	22	
Advisory Group Meeting - Overview meeting 3	Oct-03	26	
Public Informational Meeting - IRP Process overview, solicit input on objectives and measures	Oct-03	48	
Load Forecast Committee Meeting - meeting 1	Nov-03	73	
Supply-Side Committee Meeting - meeting 1	Nov-03	74	
DSM Committee Meeting - meeting 1	Dec-03	80	
Load Forecast Committee Meeting - meeting 2	Dec-03	82	
DSM Committee Meeting - meeting 2	Dec-03	88	
Advisory Group Meeting - Revised IRP Objectives, Draft IRP Scope, Distributed Generation	Dec-03	89	
DG/CHP Committee Meeting - meeting 1	Dec-03	90	
DSM Committee Meeting - meeting 3	Dec-03	95	
Supply-Side Committee Meeting - meeting 2	Dec-03	97	
DG/CHP Committee Meeting - meeting 2	Jan-04	131	
Load Forecast Committee Meeting - meeting 3	Jan-04	135	
Advisory Group Meeting - 2004 Sales & Peak Forecast, Quantified Values for IRP Objectives	Mar-04	186	
DSM Committee Meeting - meeting 4	Mar-04	194	
DSM Committee Meeting - meeting 5	Apr-04	207	
DG/CHP Committee Meeting - meeting 3	Apr-04	214	
DSM Committee Meeting - meeting 6	Apr-04	221	
Begin Integration Process	Apr-04	221	Integration Analysis - 18 months
Integration Technical Committee Meeting - meeting 1	Apr-04	223	
Supply Side Committee Meeting - meeting 3	Apr-04	226	
Integration Technical Committee Meeting - meeting 2	May-04	240	
DG/CHP Committee Meeting - meeting 4	May-04	251	
Complete Development of Objectives and Assumptions	May-04	251	
Advisory Group Meeting - Technical Committees Results	May-04	256	
Integration Technical Committee Meeting - meeting 3	Aug-04	354	
Integration Technical Committee Meeting - meeting 4	Sep-04	381	
Integration Technical Committee Meeting - meeting 5	Nov-04	423	
Advisory Group Meeting - Integration TC Results, Macroeconomic Impacts (UHERO)	Nov-04	430	
Public Informational Meeting - solicit input on Finalist Plans	Nov-04	432	
Advisory Group Meeting - Review of Finalist Plans and Public Comments, AG Input to Selection of Preferred Plan	Dec-04	451	
Publish Draft Report for Advisory Group & public review	Jun-05	639	
Advisory Group Meeting - Review of Draft Preferred Plan and Action Plan	Jul-05	675	
File Final IRP Report with the PUC	Oct-05	776	

Proposed 1-Year IRP Plan Development Timeline

Duration of Major Tasks (Approx.)	Day No. (Approx.)	Subject
Cont. Mtgs.		Continuous AG/Technical Committee Meetings to update assumptions (1-2 mtgs./yr.)
	0	PUC Order Opening Docket for IRP
Develop Objectives and Finalize Assumptions - 1 month	1	Begin Development of Objectives and Finalize Assumptions
	8	Advisory Group Meeting - Provide input on Objectives & Measures and Assumptions
	15	Public Informational Meeting - Provide input on Objectives & Measures and Assumptions
	30	Complete Development of Objectives and Assumptions
Integration Analysis - 11 months	31	Begin Integration Analysis
	167	Public Informational Meeting - Present integration results, solicit input on Draft Plan
	189-195	Advisory Group Meetings - Present integration results, solicit input on Draft Plan
	365	File Final IRP Report with the PUC

Note: Provided for discussion purposes only to Parties in the Competitive Bidding Docket No. 03-0372 to illustrate a potential schedule to develop and file an IRP in a one-year timeframe to accommodate the possible use of competitive bidding to acquire the resources or block of resources included in the IRP. A one-year IRP development process would result in significantly less public participation and transparency, which HECO deems to be very important. HECO is willing to discuss alternative approaches.

EXHIBIT "D"
Page 4 of 4

CERTIFICATE OF SERVICE

I hereby certify that I have this date served a copy of the foregoing **OPENING BRIEF, EXHIBITS "A" – "D",** together with this Certificate of Service, by hand delivery and/or by mailing a copy by United States mail, postage prepaid, to the following:

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